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INT $CL^7$ **E21B**
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Additional Fields
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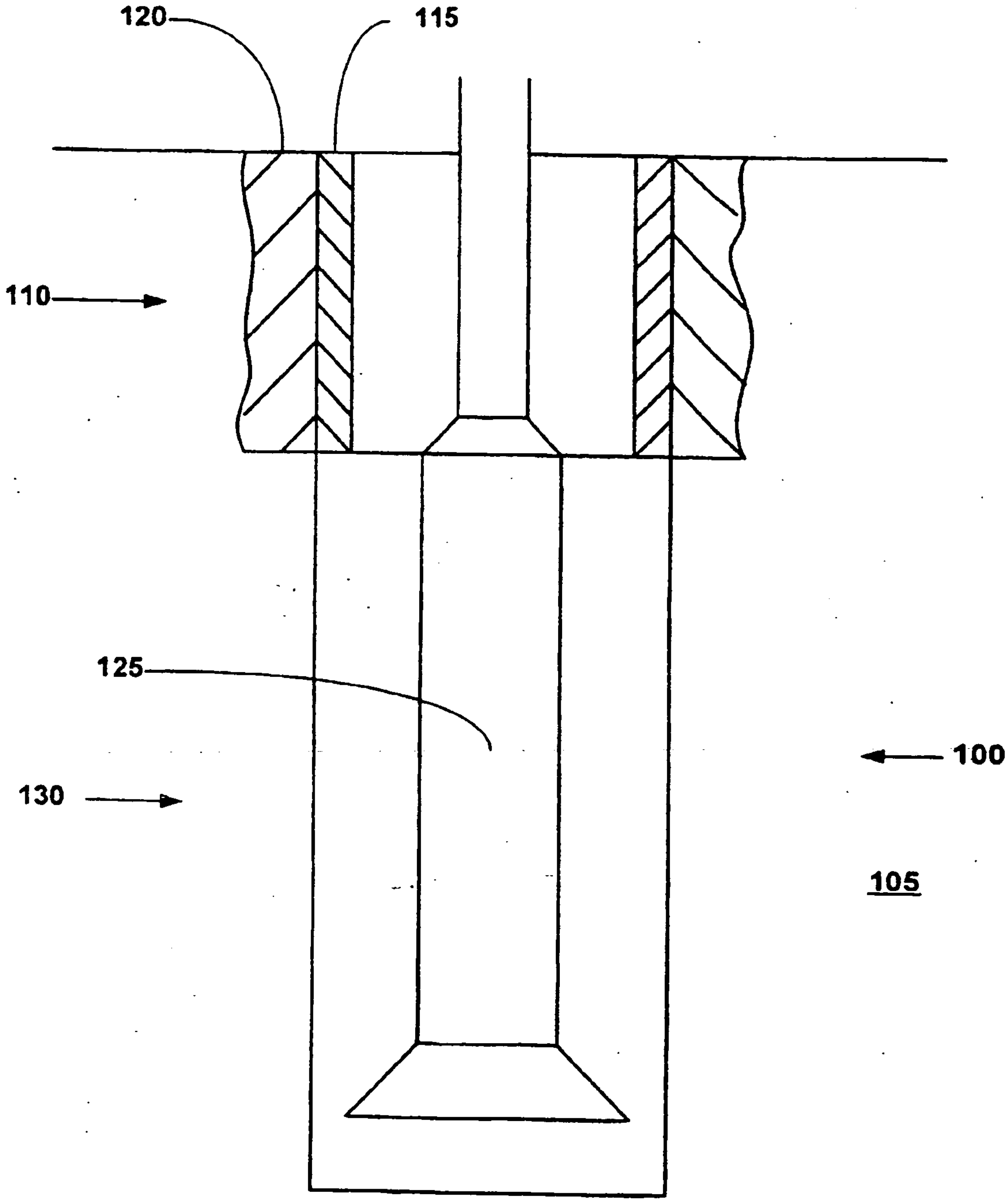


FIG. 1

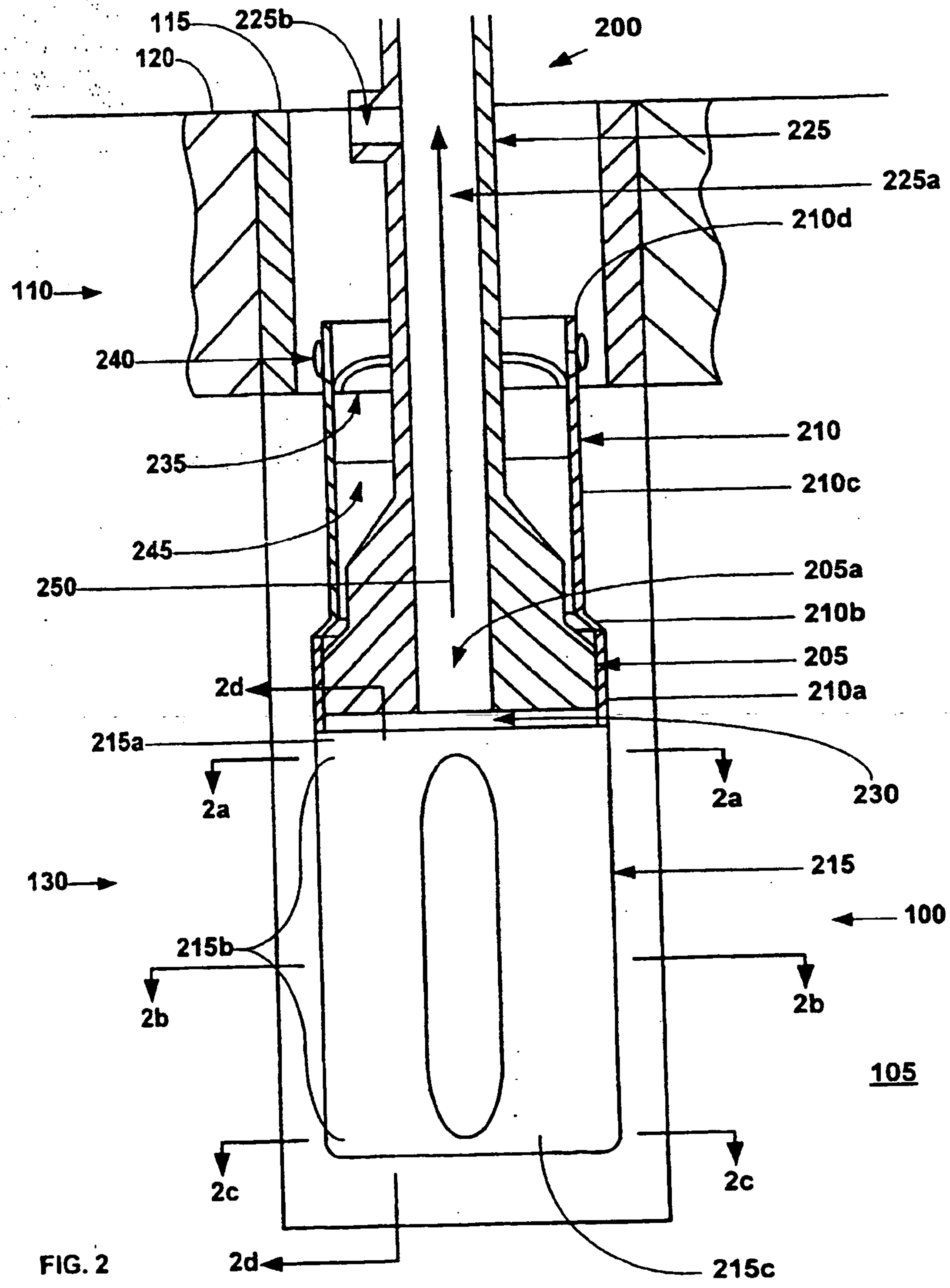

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FIG. 2

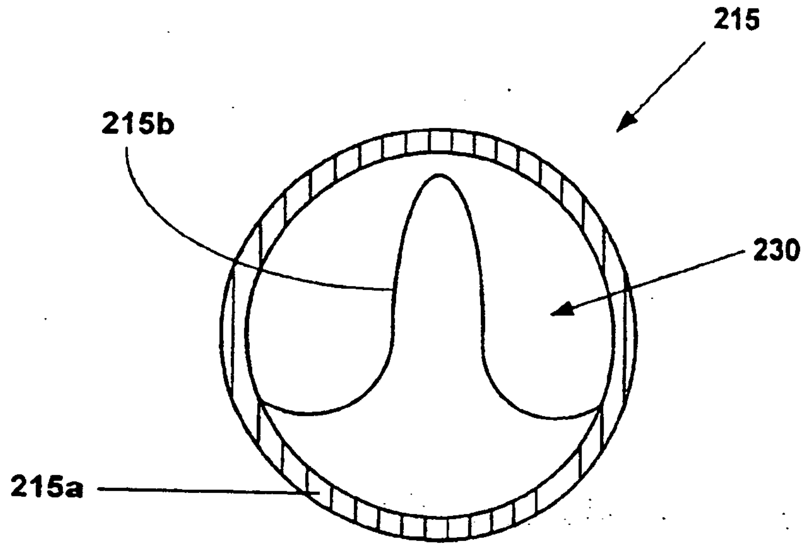


FIG. 2a

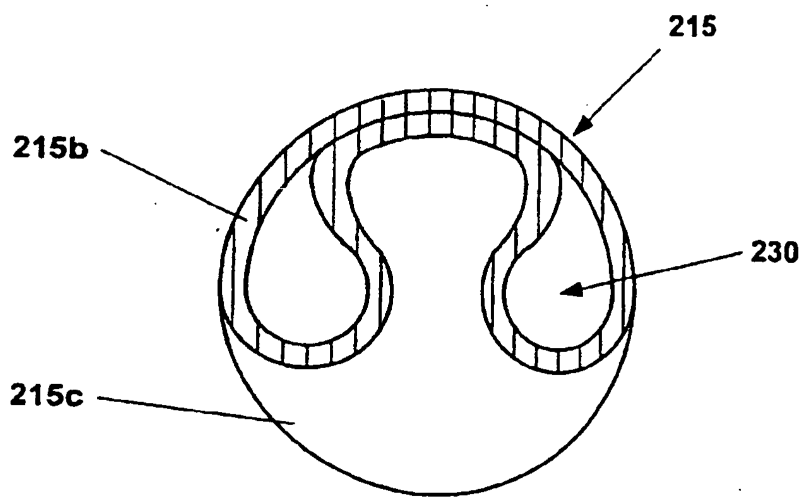


FIG. 2b

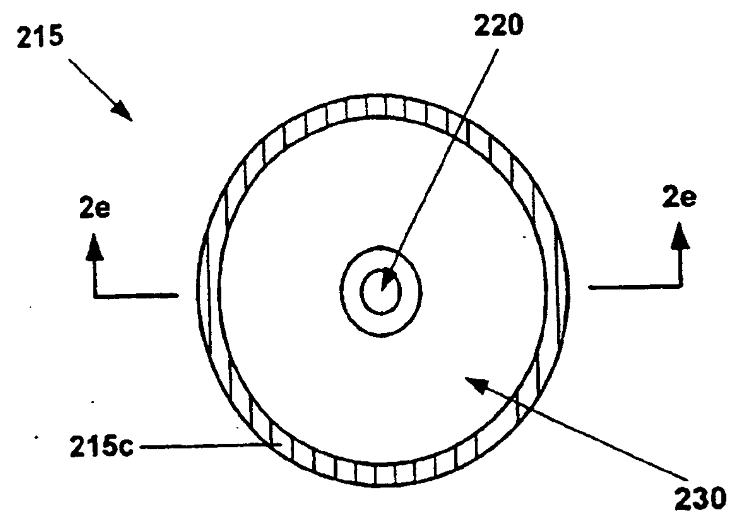


FIG. 2c

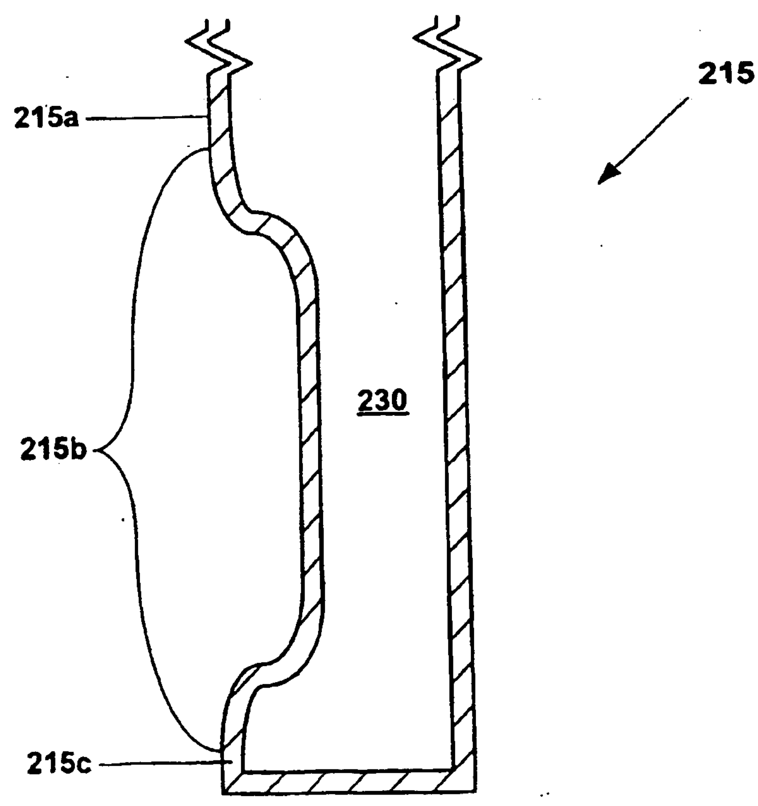


FIG. 2d

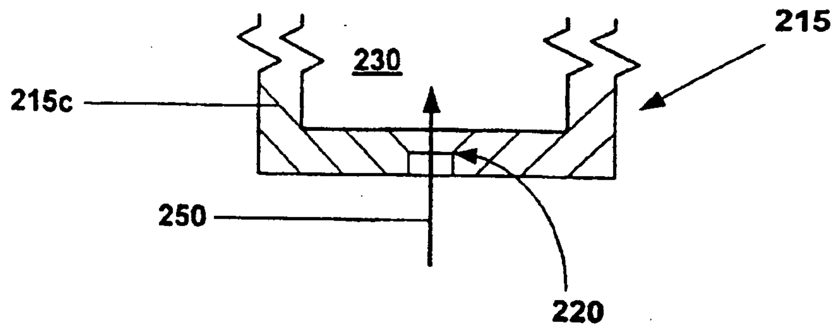


FIG. 2e

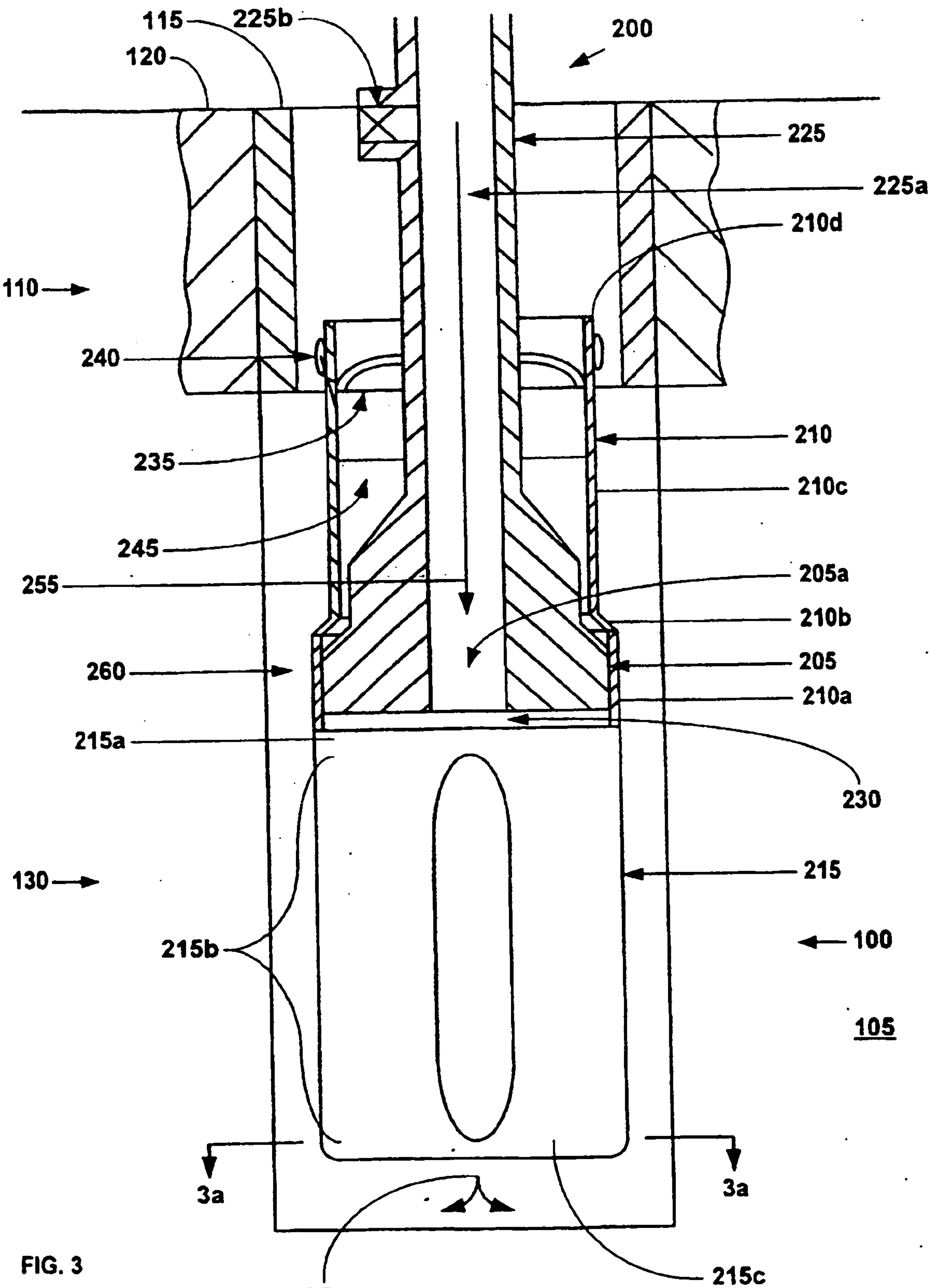
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FIG. 3

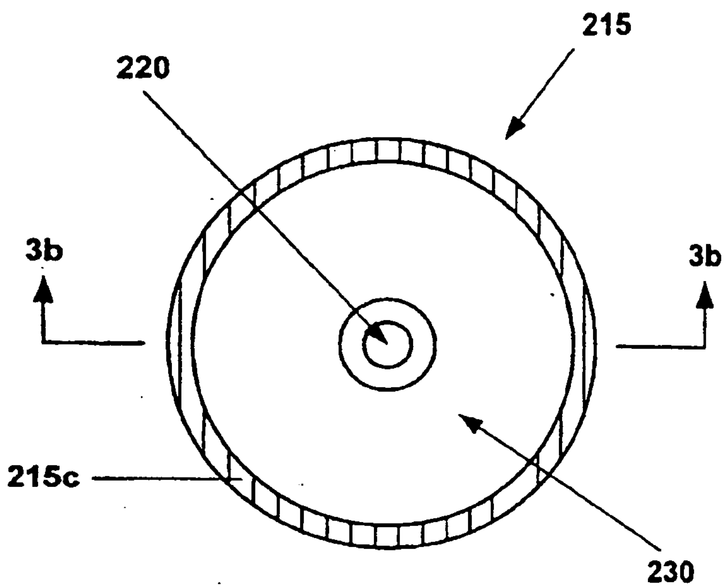


FIG. 3a

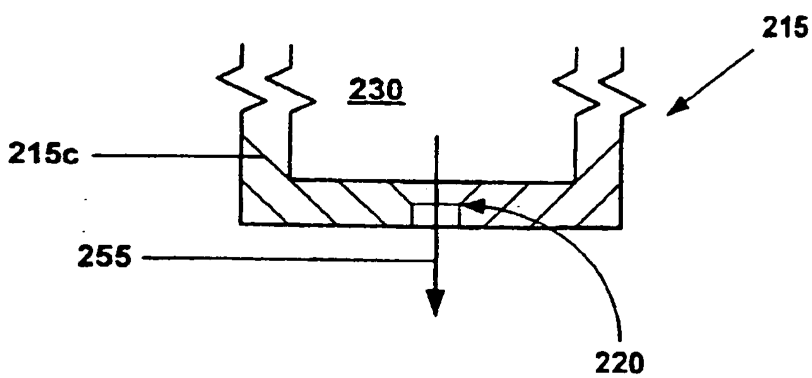


FIG. 3b

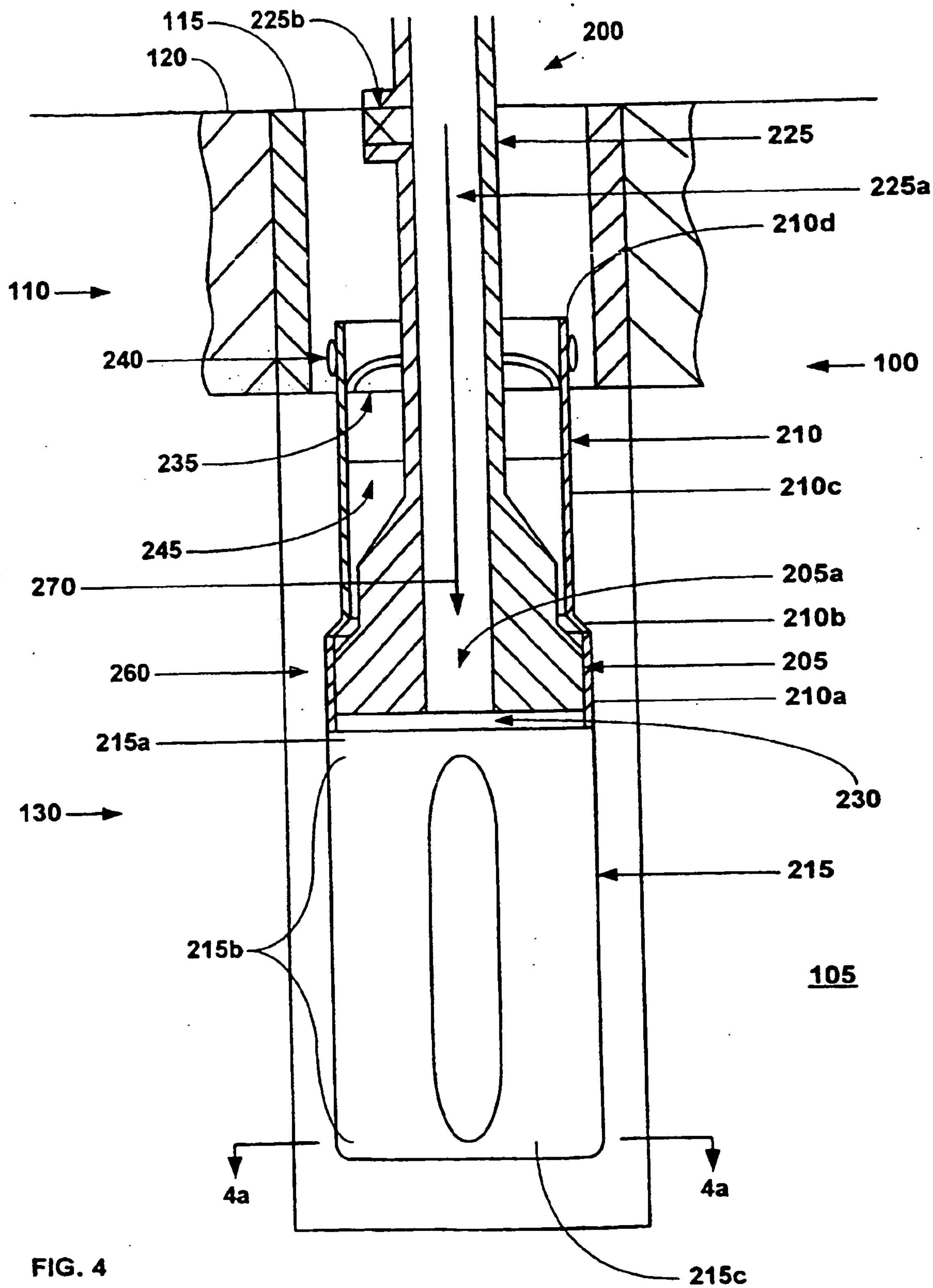
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FIG. 4

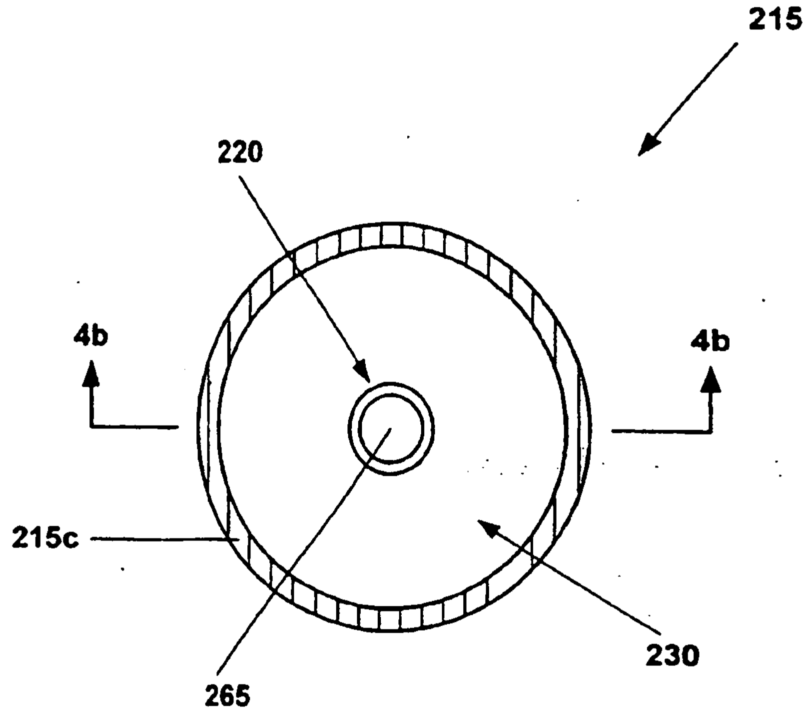


FIG. 4a

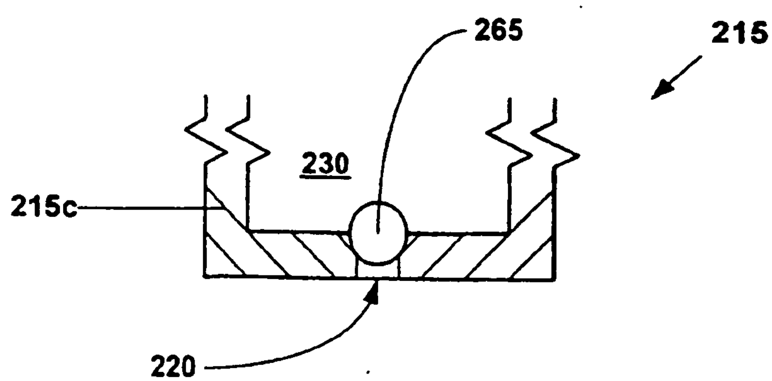


FIG. 4b

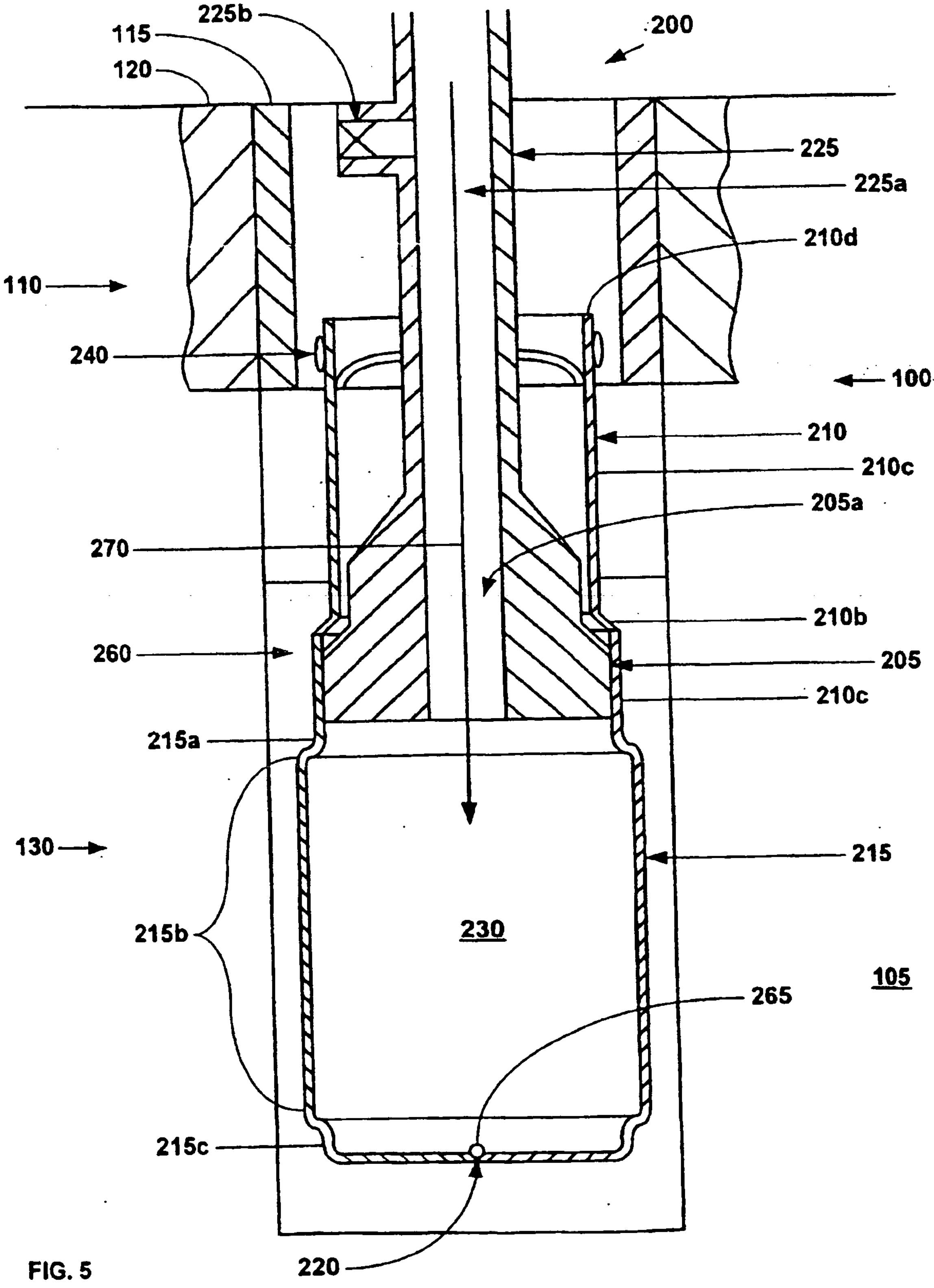

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FIG. 5

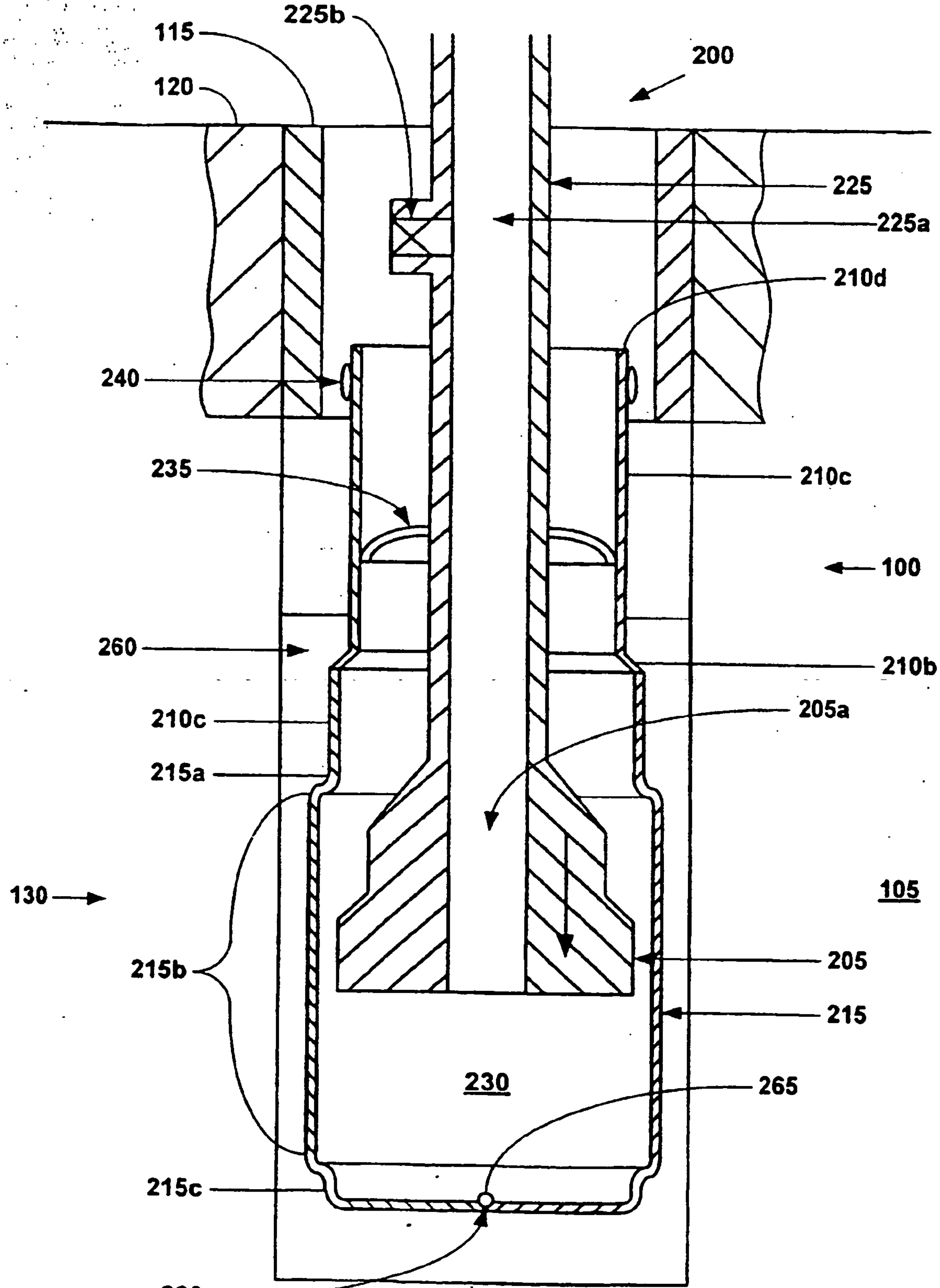
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FIG. 6

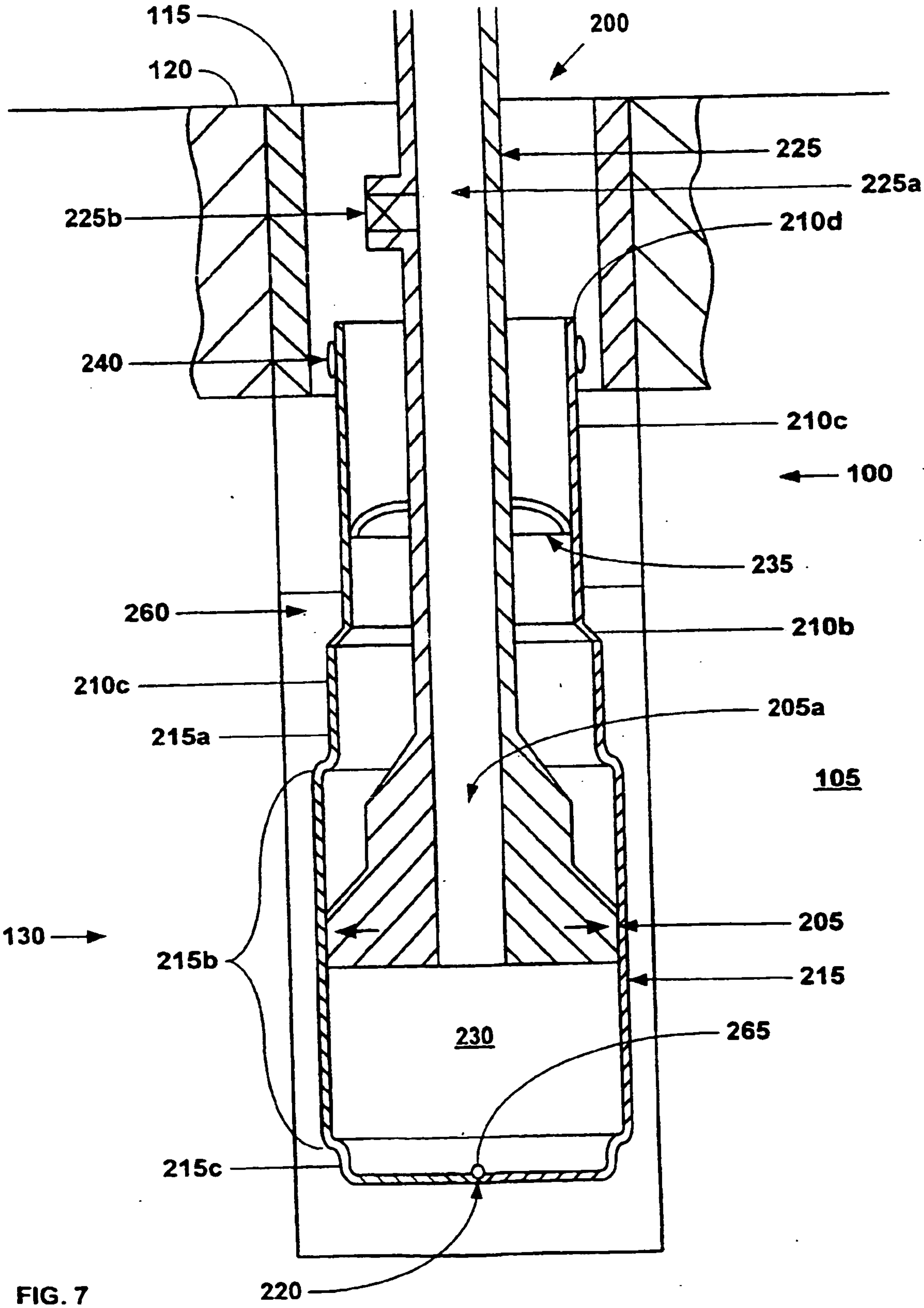
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FIG. 7

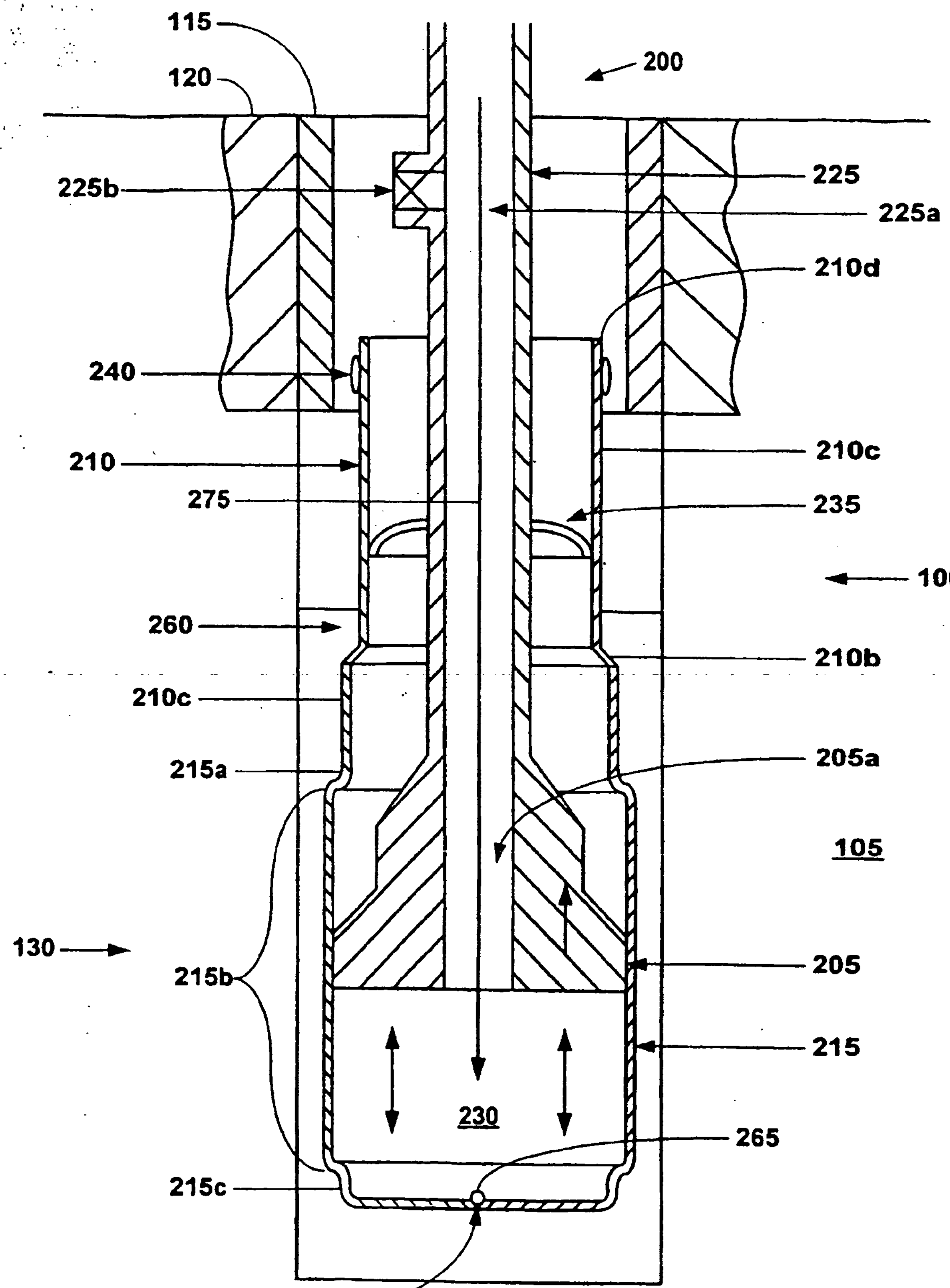
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FIG. 8

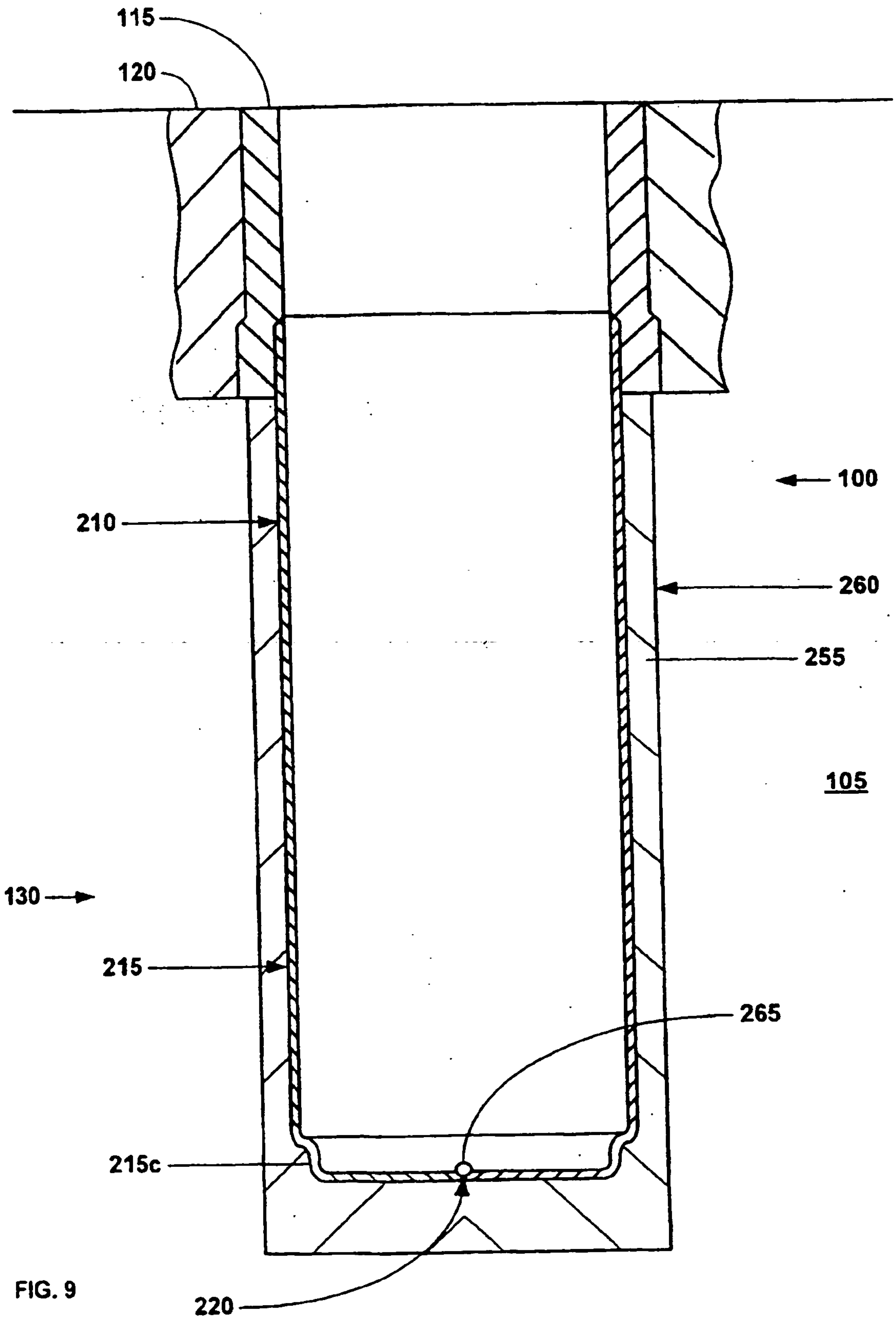


FIG. 9

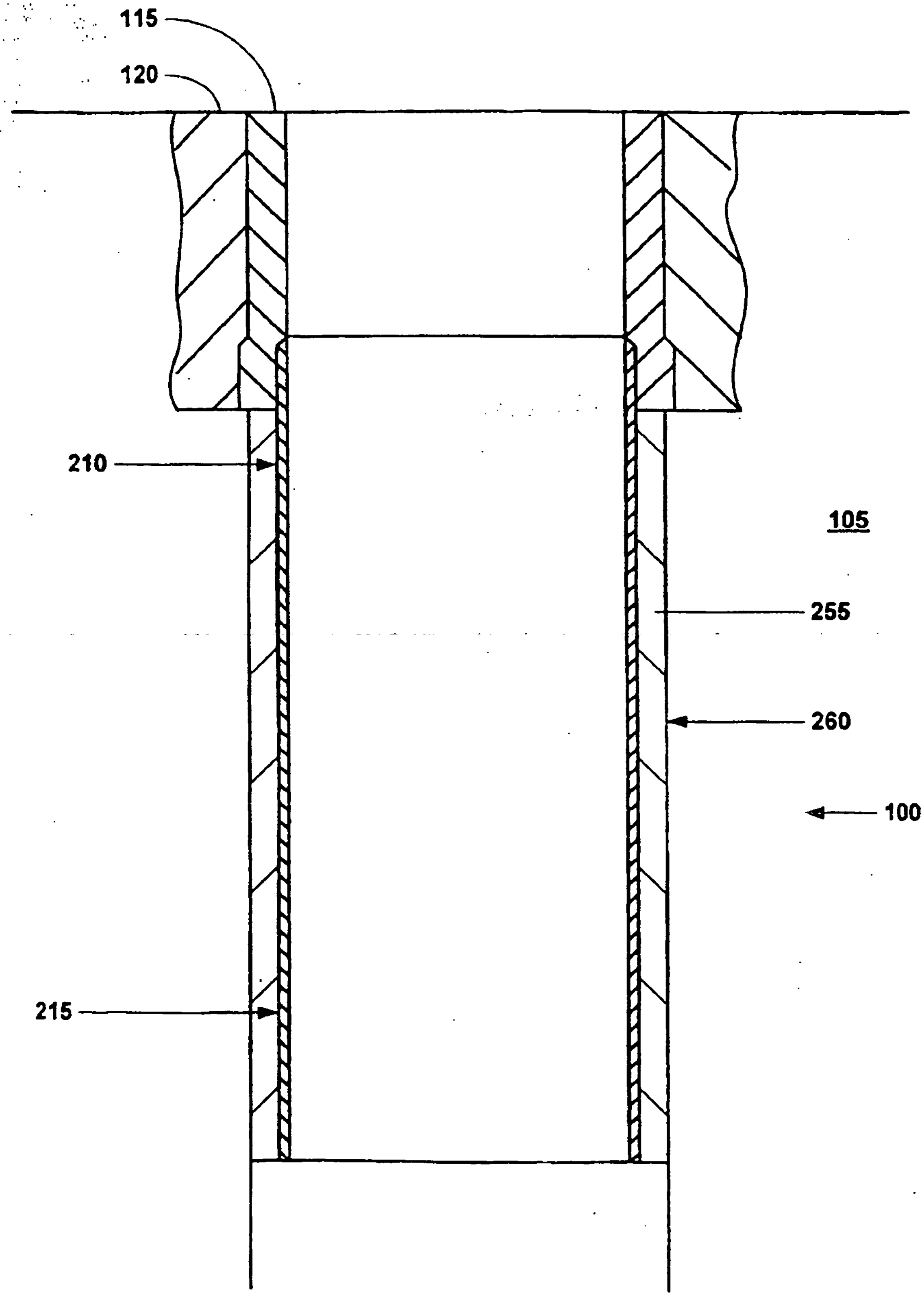


FIG. 10

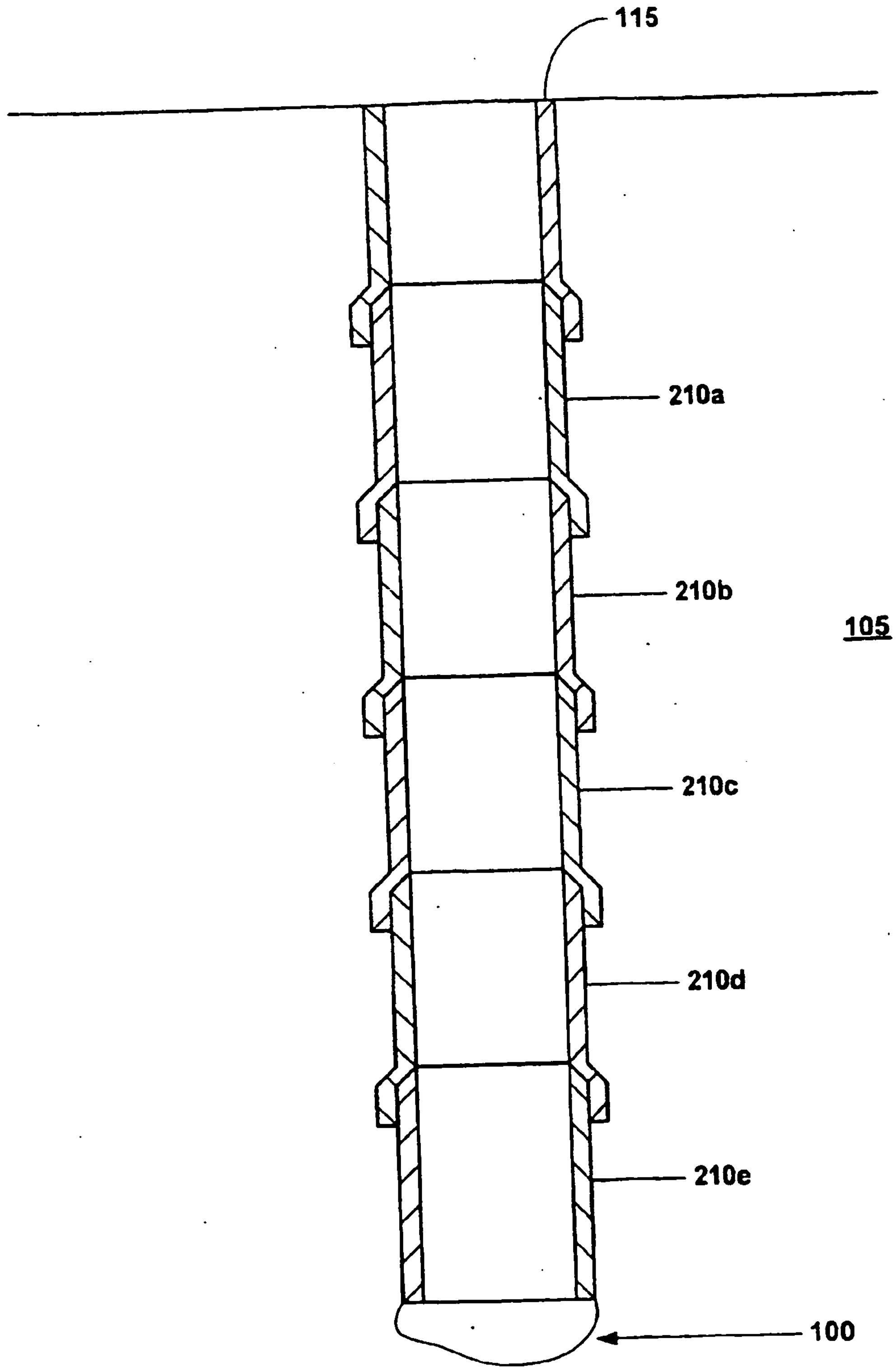


FIG. 11

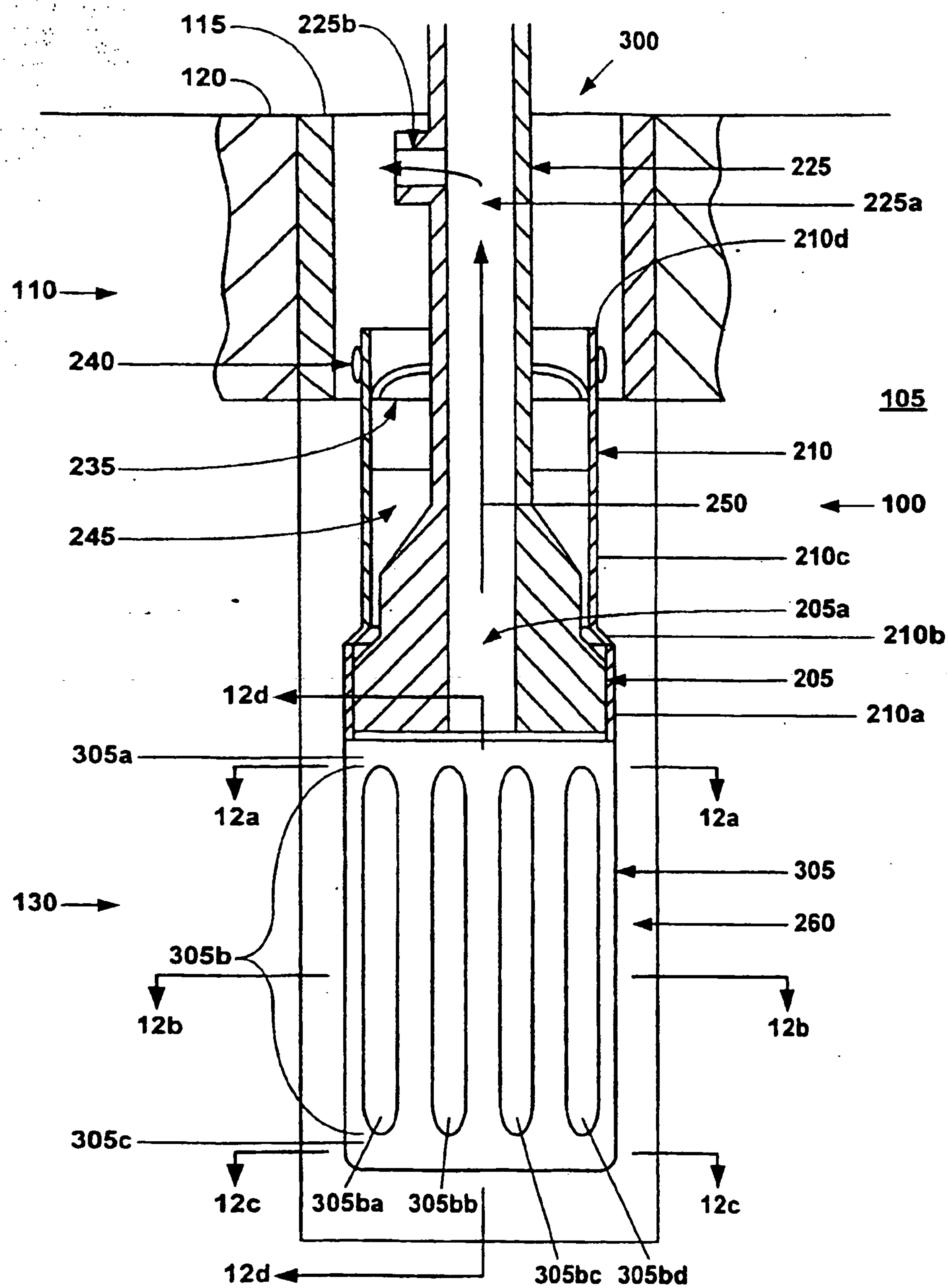
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FIG. 12

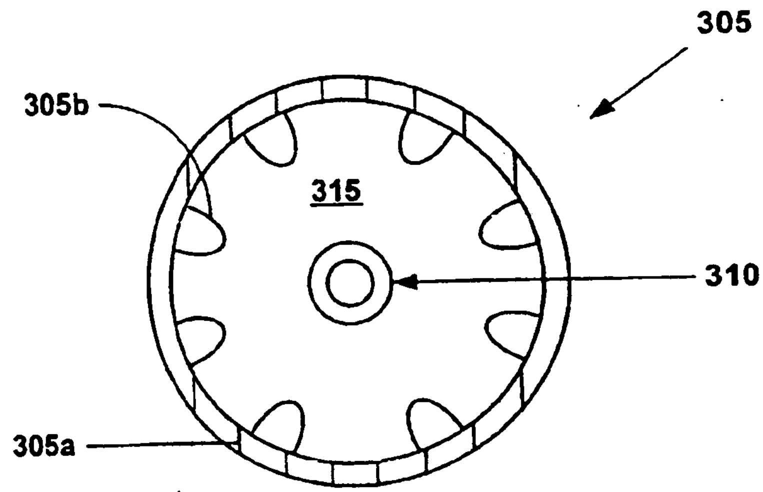


FIG. 12a

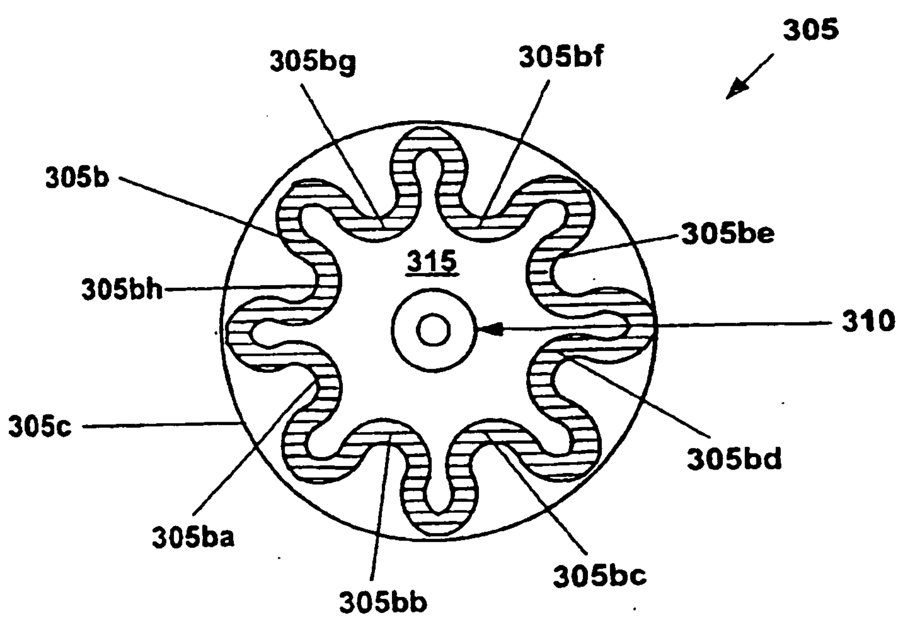


FIG. 12b

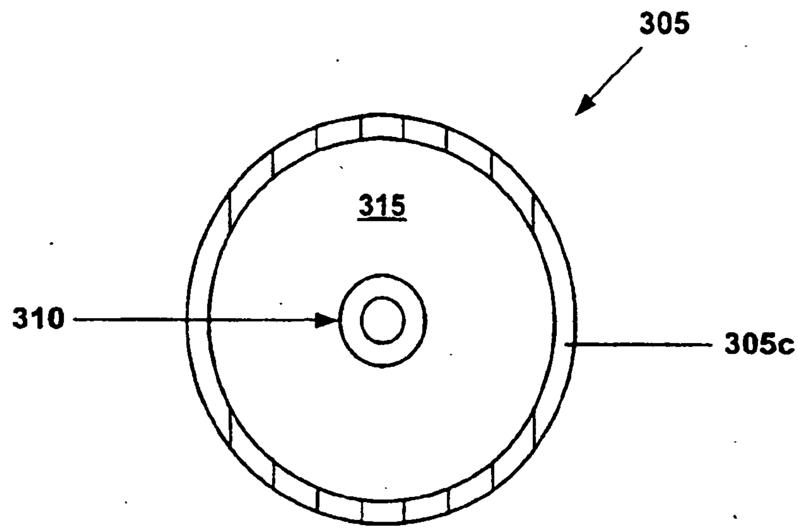


FIG. 12c

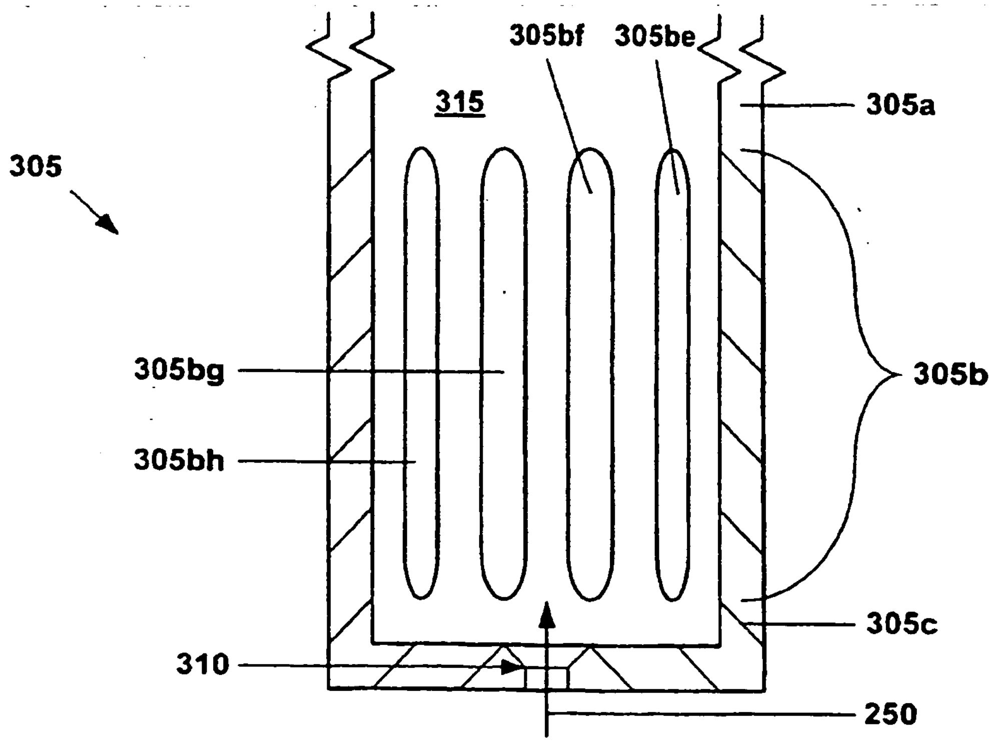


FIG. 12d

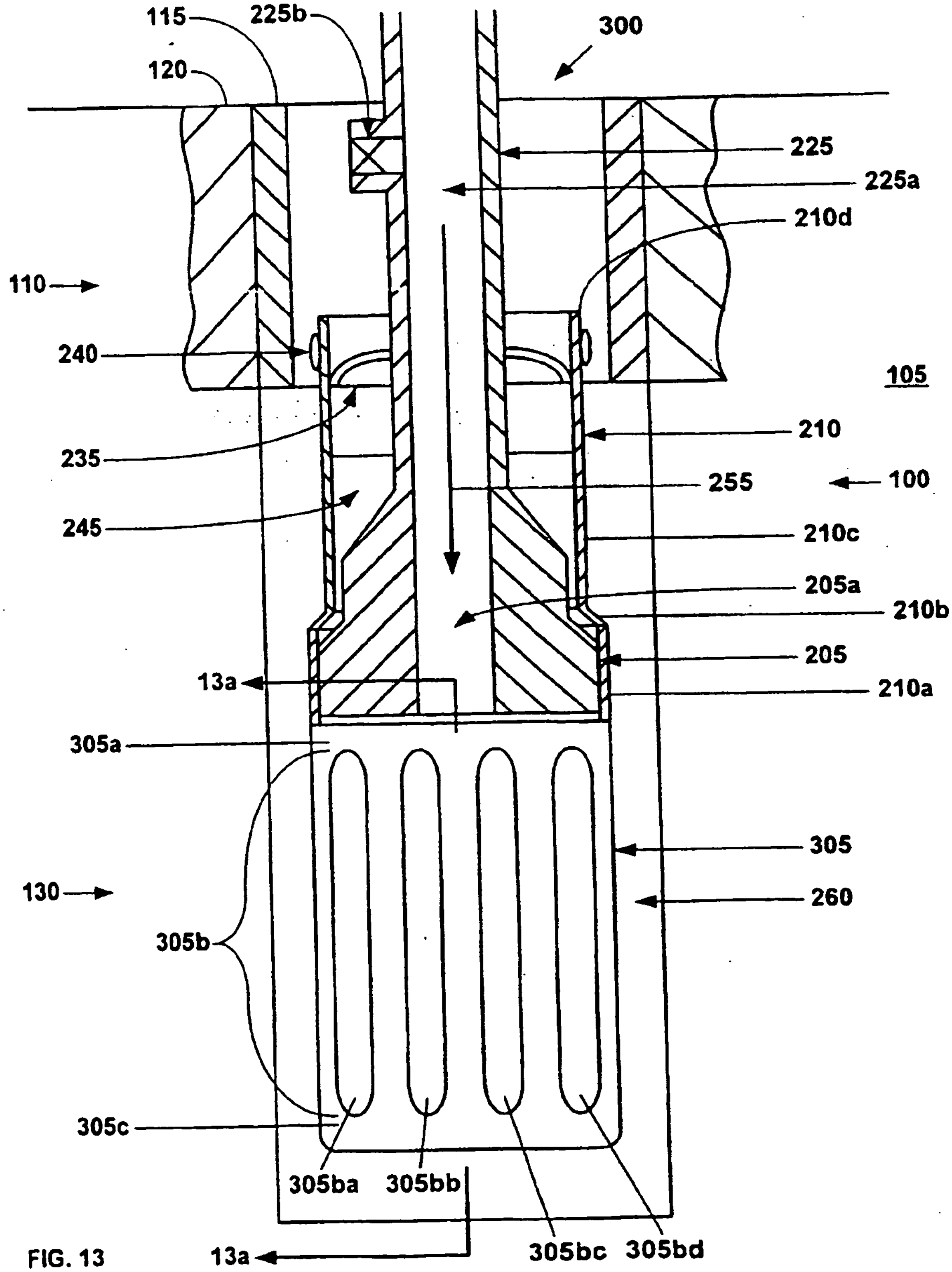

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FIG. 13

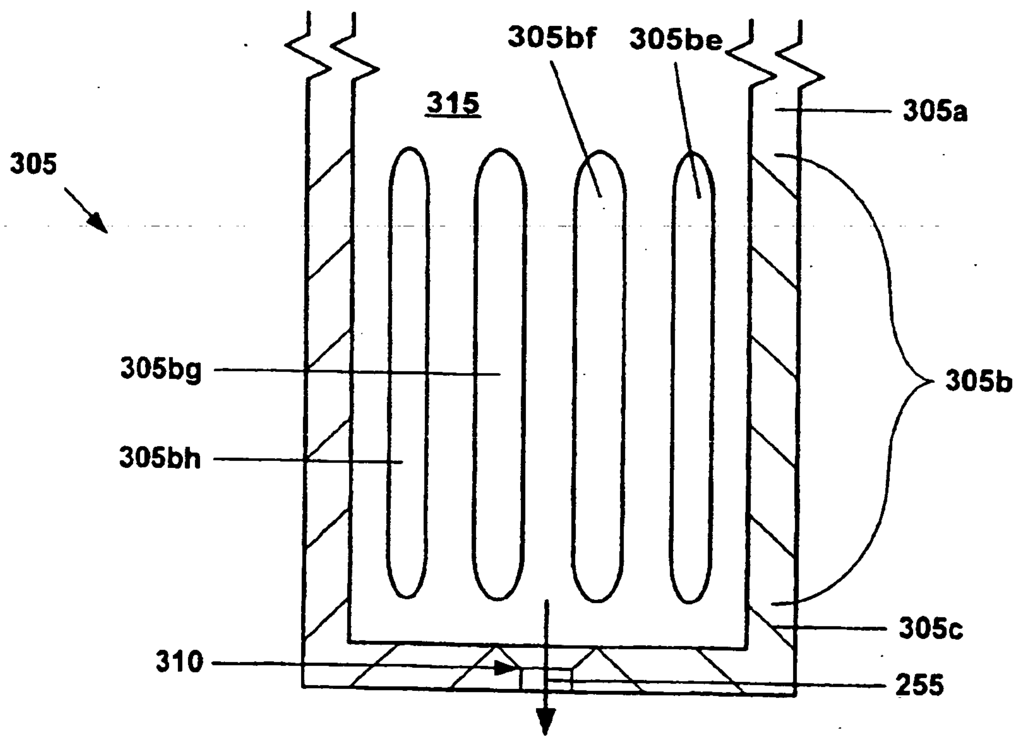


FIG. 13a

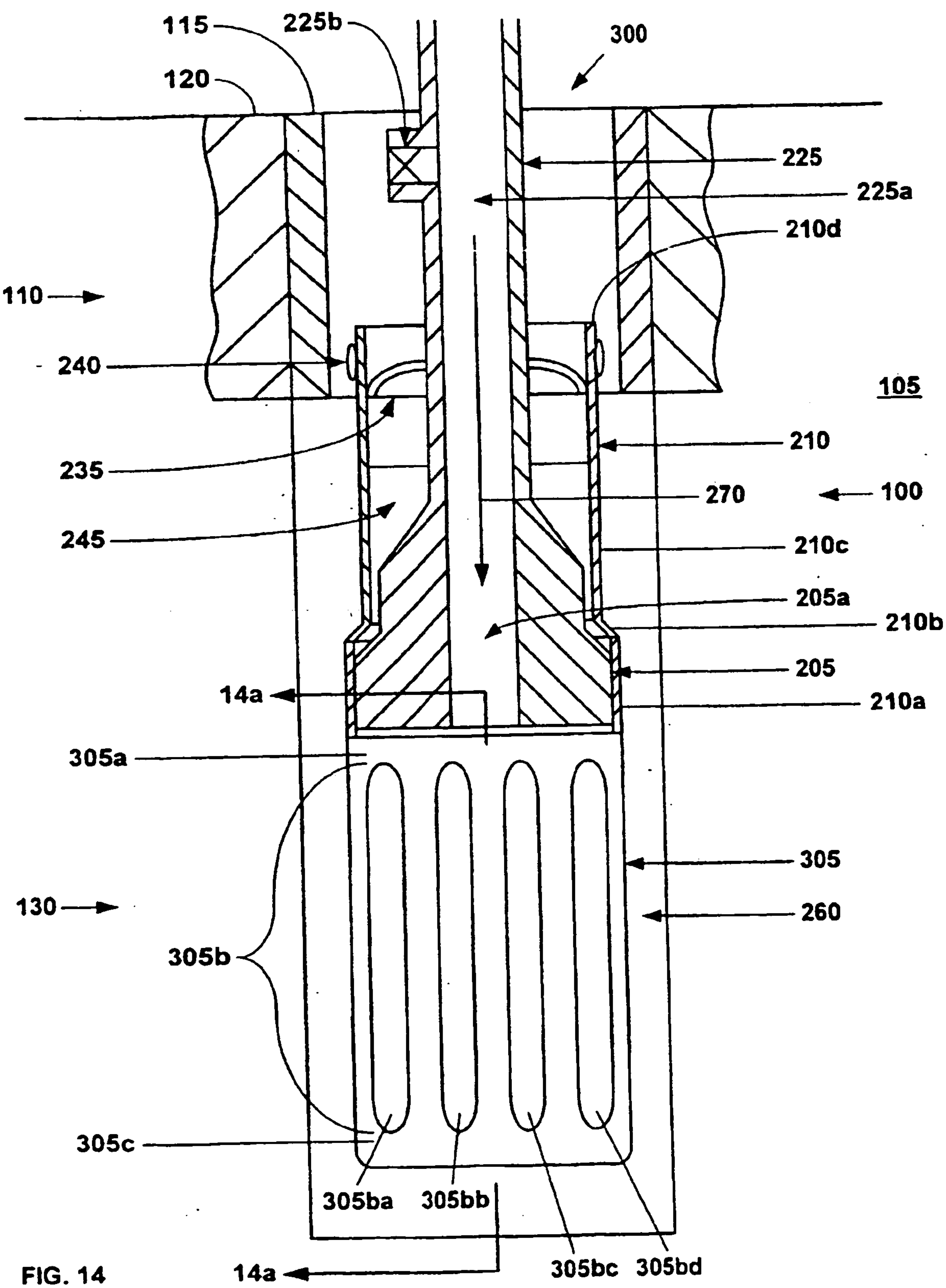
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FIG. 14

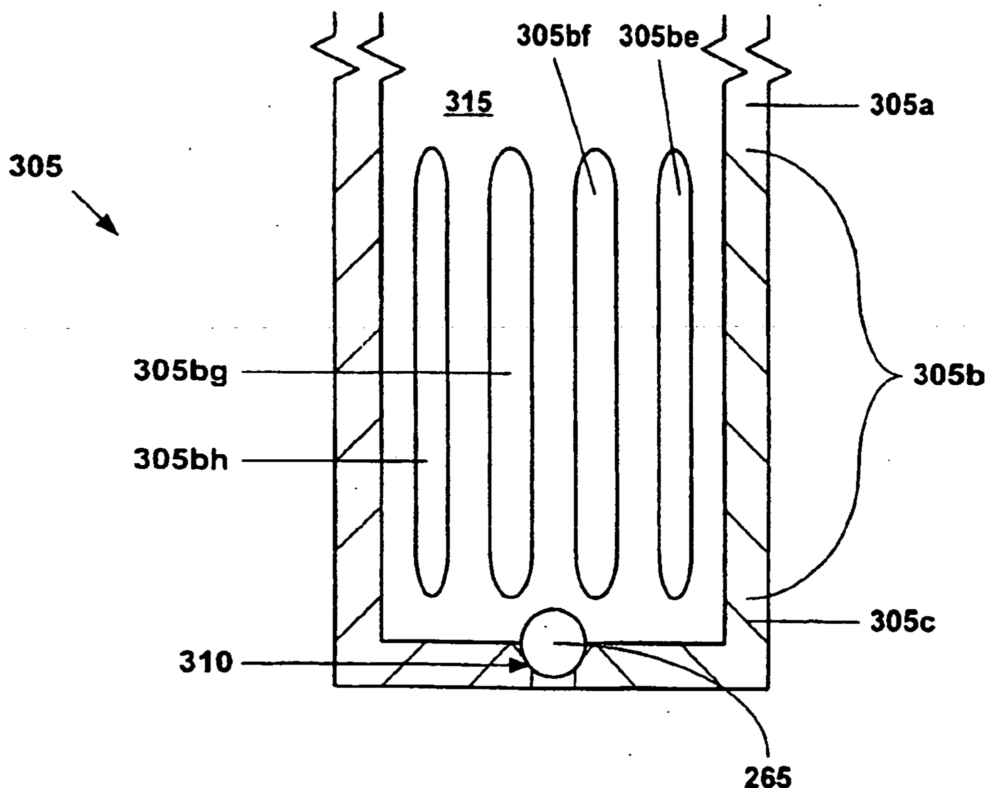


FIG. 14a

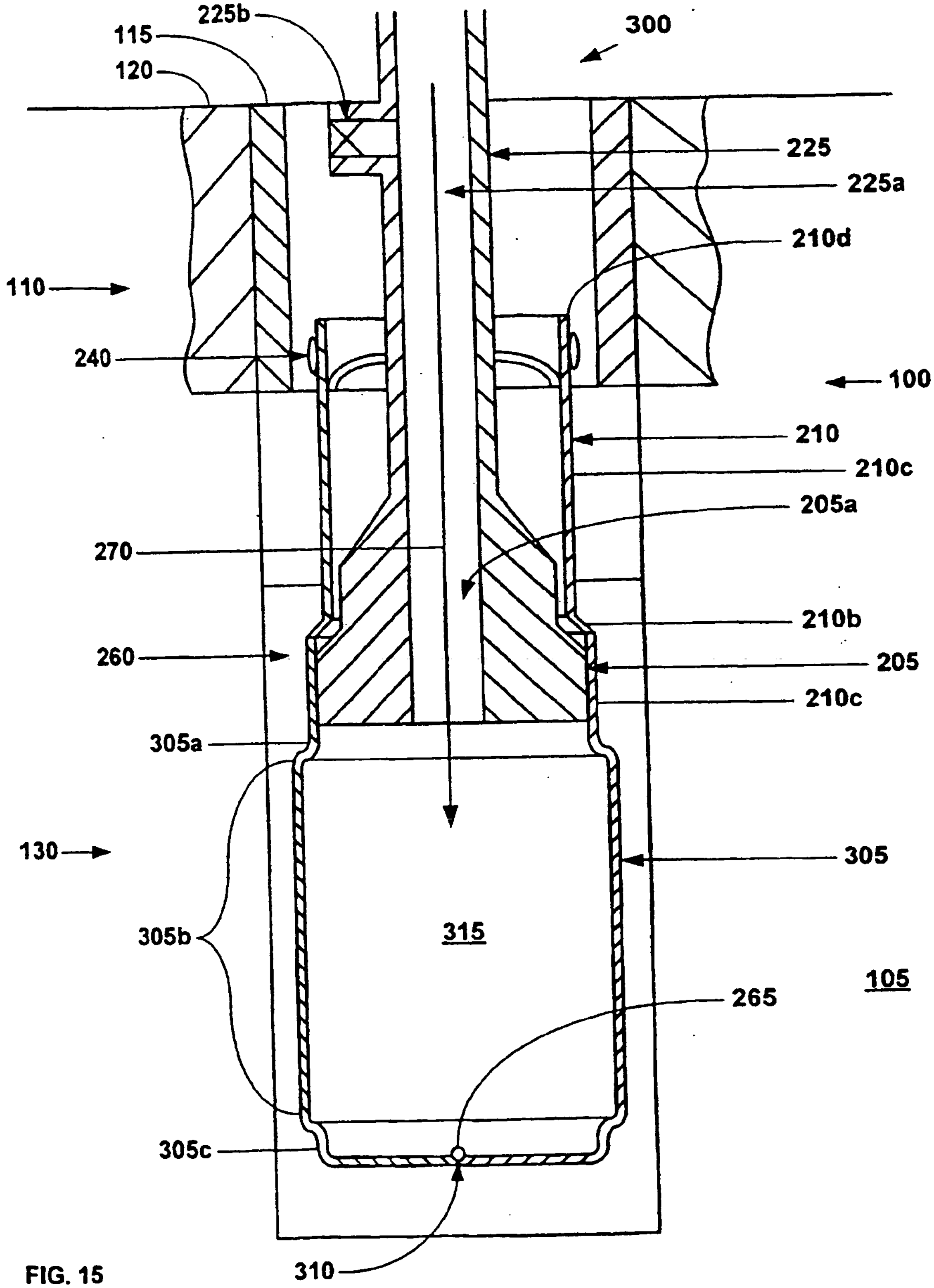
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FIG. 15

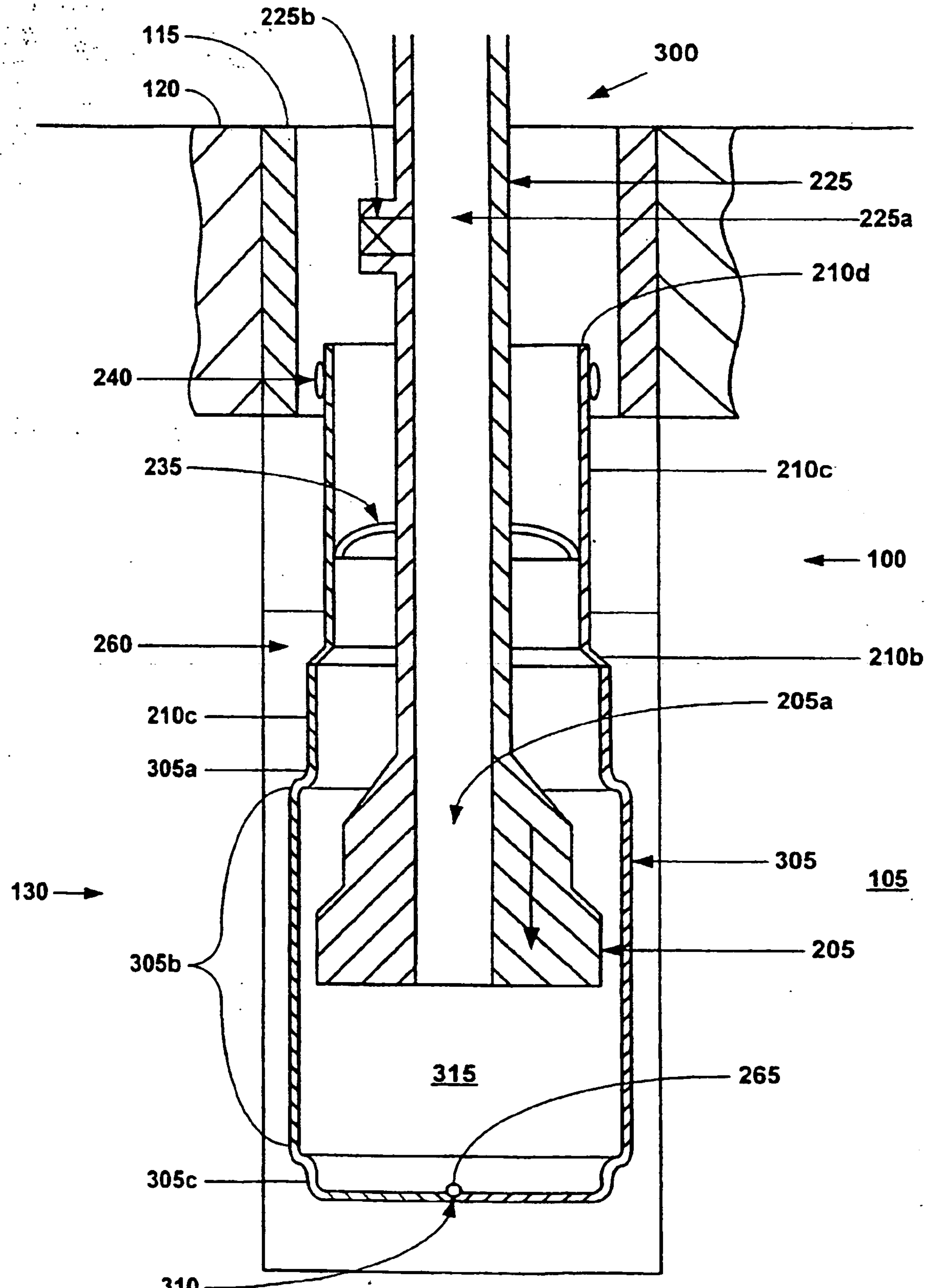
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FIG. 16

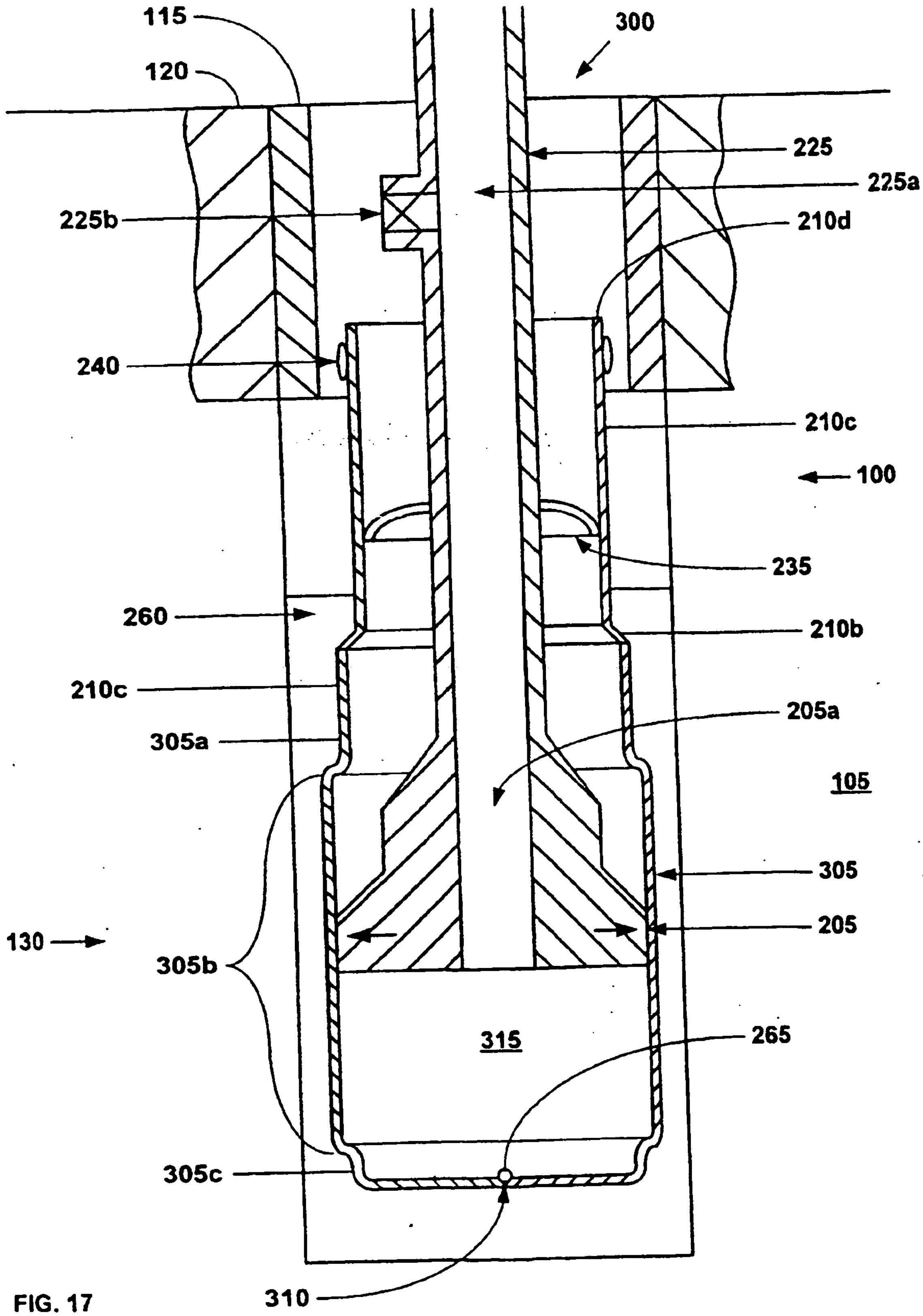

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FIG. 17

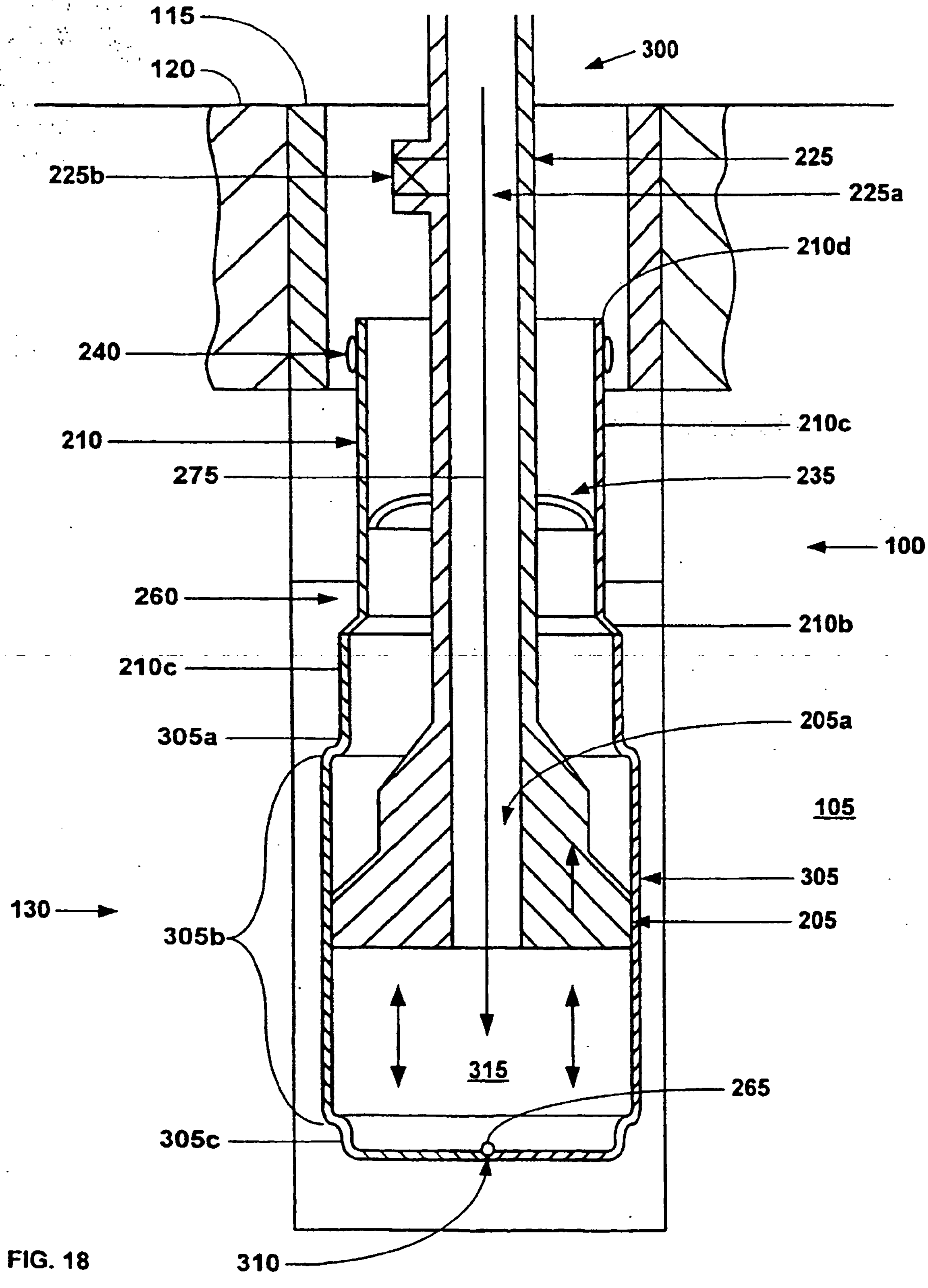
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FIG. 18

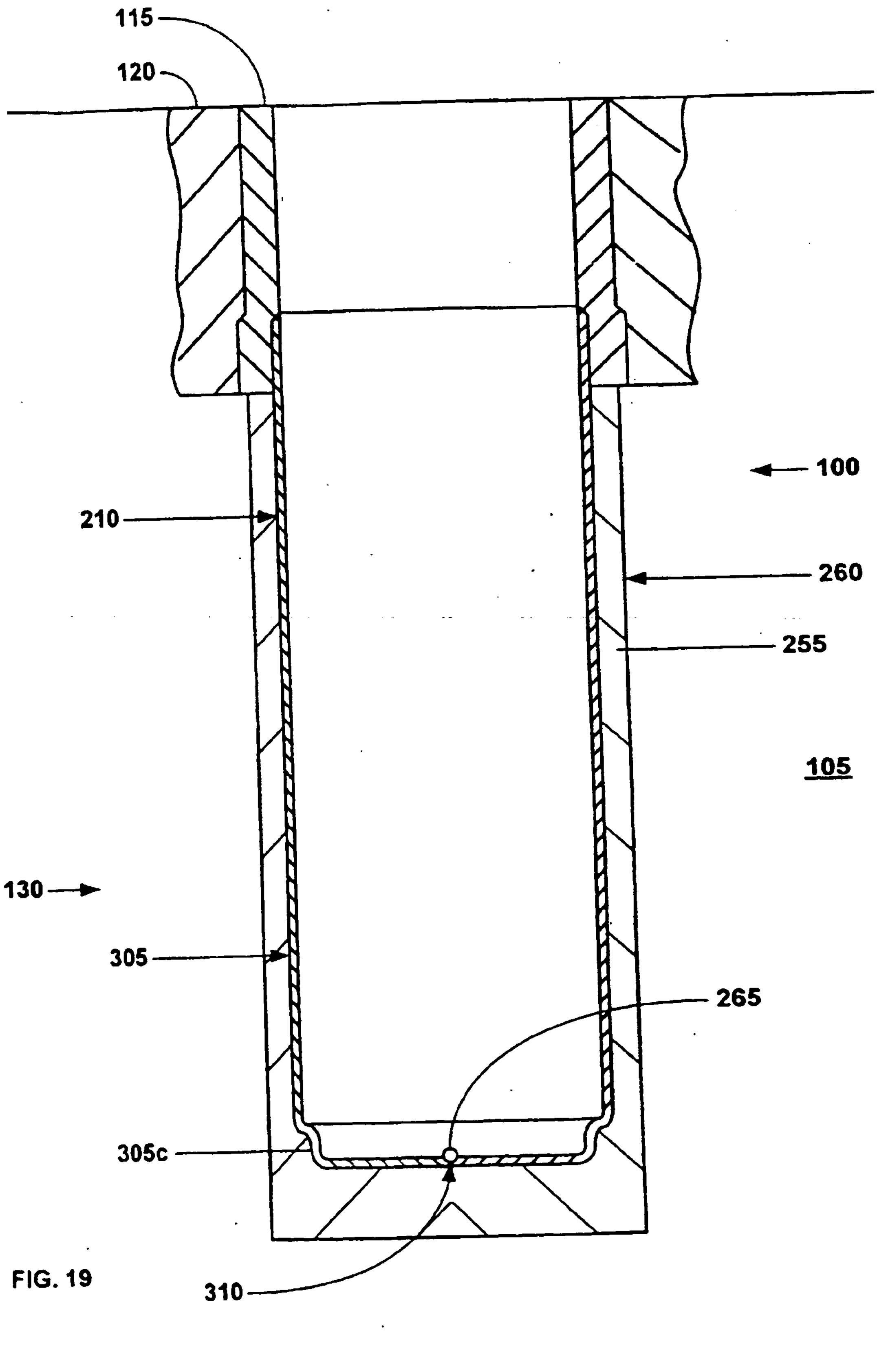

FIG. 19

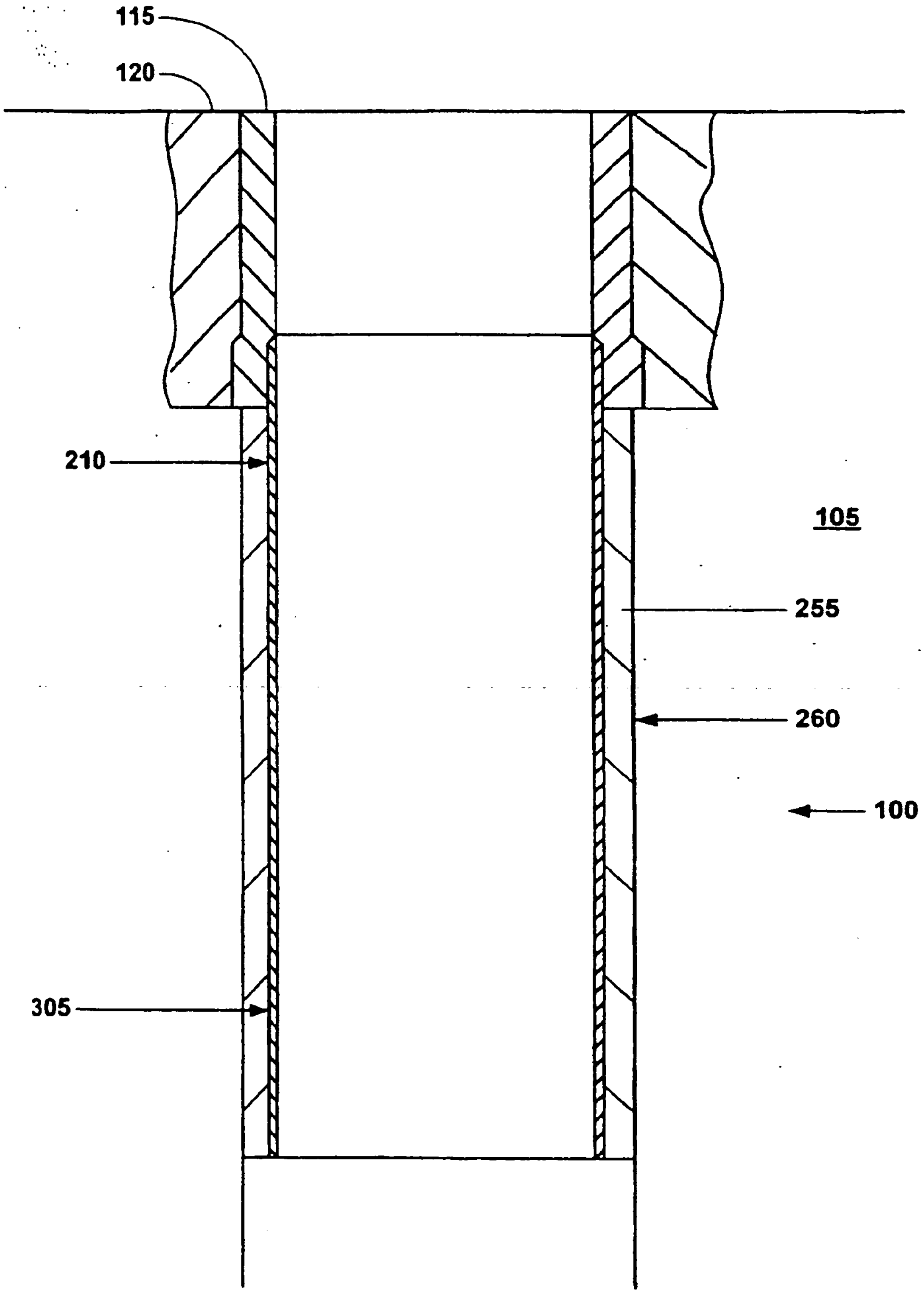


FIG. 20

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# MONO-DIAMETER WELLBORE CASING

This invention relates generally to a wellbore casing, and in particular to an apparatus and method for forming a wellbore casing using expandable tubing.

## Background of the Invention

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested embodiment with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested embodiment a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming new sections of casing in a wellbore.

## Summary of the Invention

According to the present invention there is provided an apparatus for forming a wellbore casing within a subterranean formation including a preexisting wellbore casing positioned in a borehole, comprising:

a tubular liner; and

means for radially expanding and coupling the tubular liner to an overlapping portion of the preexisting wellbore casing;

wherein the inside diameter of the radially expanded tubular liner is equal to the inside diameter of a non-overlapping portion of the preexisting wellbore casing, and

wherein the means for radially expanding and coupling the tubular liner comprises an expandable shoe coupled to the tubular liner.

According to another aspect of the present invention there is provided an apparatus for forming a tubular structure within a subterranean formation including a preexisting tubular member positioned in a borehole, comprising:

a tubular liner; and

means for radially expanding and coupling the tubular liner to an overlapping portion of the preexisting tubular member;

wherein the inside diameter of the radially expanded tubular liner is equal to the inside diameter of a non-overlapping portion of the preexisting tubular member, and

wherein the means for radially expanding and coupling the tubular liner comprises an expandable shoe coupled to the tubular liner.

## Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a mono-diameter wellbore casing within the new section of the well borehole of FIG. 1.

FIG. 2a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 2.

FIG. 2b is a cross-sectional view of another portion of the shoe of the apparatus of FIG. 2.

FIG. 2c is a cross-sectional view of another portion of the shoe of the apparatus of FIG. 2.

FIG. 2d is a cross-sectional view of another portion of the shoe of the apparatus of FIG. 2.

FIG. 2e is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 2c.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a hardenable fluidic sealing material through the apparatus and into the new section of the well borehole of FIG. 2.

FIG. 3a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 3.

FIG. 3b is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 3a.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a fluidic material into the apparatus of FIG. 3 in order to fluidicly isolate the interior of the shoe.

FIG. 4a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 4.

FIG. 4b is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 4a.

FIG. 5 is a cross-sectional view illustrating the radial expansion of the shoe of FIG. 4.

FIG. 6 is a cross-sectional view illustrating the lowering of the expandable expansion cone into the radially expanded shoe of the apparatus of FIG. 5.

FIG. 7 is a cross-sectional view illustrating the expansion of the expandable expansion cone of the apparatus of FIG. 6.

FIG. 8 is a cross-sectional view illustrating the injection of fluidic material into the radially expanded shoe of the apparatus of FIG. 7.

FIG. 9 is a cross-sectional view illustrating the completion of the radial expansion of the expandable tubular member of the apparatus of FIG. 8.

FIG. 10 is a cross-sectional view illustrating the removal of the bottom portion of the radially expanded shoe of the apparatus of FIG. 9.

FIG. 11 is a cross-sectional view illustrating the formation of a mono-diameter wellbore casing that includes a plurality of overlapping mono-diameter wellbore casings.

FIG. 12 is a fragmentary cross-sectional view illustrating the placement of an alternative embodiment of an apparatus for creating a mono-diameter wellbore casing within the wellbore of FIG. 1.

FIG. 12a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 12.

FIG. 12b is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 12.

FIG. 12c is a cross-sectional view of another portion of the shoe of the apparatus of FIG. 12.

FIG. 12d is a cross-sectional view of another portion of the shoe of the apparatus of FIG. 12.

FIG. 13 is a fragmentary cross-sectional view illustrating the injection of a hardenable fluidic sealing material through the apparatus and into the new section of the well borehole of FIG. 12.

FIG. 13a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 13.

FIG. 14 is a fragmentary cross-sectional view illustrating the injection of a fluidic material into the apparatus of FIG. 13 in order to fluidicly isolate the interior of the shoe.

FIG. 14a is a cross-sectional view of a portion of the shoe of the apparatus of FIG. 14.

FIG. 15 is a cross-sectional view illustrating the radial expansion of the shoe of FIG. 14.

FIG. 16 is a cross-sectional view illustrating the lowering of the expandable expansion cone into the radially expanded shoe of the apparatus of FIG. 15.

FIG. 17 is a cross-sectional view illustrating the expansion of the expandable expansion cone of the apparatus of FIG. 16.

FIG. 18 is a cross-sectional view illustrating the injection of fluidic material into the radially expanded shoe of the apparatus of FIG. 17.

FIG. 19 is a cross-sectional view illustrating the completion of the radial expansion of the expandable tubular member of the apparatus of FIG. 18.

FIG. 20 is a cross-sectional view illustrating the removal of the bottom portion of the radially expanded shoe of the apparatus of FIG. 19.

Detailed Description of the Illustrative Embodiments

Referring initially to FIGS. 1, 2, 2a, 2b, 2c, 2d, 2e, 3, 3a, 3b, 4, 4a, 4b, and 5-10, an embodiment of an apparatus and method for forming a mono-diameter wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes a pre-existing cased section 110 having a tubular casing 115 and an annular outer layer 120 of a fluidic sealing material such as, for example, cement. The wellbore 100 may be positioned in any orientation from vertical to horizontal. In several alternative embodiments, the pre-existing cased section 110 does not include the annular outer layer 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new wellbore section 130. In a preferred embodiment, the inside diameter of the new wellbore section 130 is greater than the inside diameter of the preexisting wellbore casing 115.

As illustrated in FIGS. 2, 2a, 2b, 2c, 2d, and 2e, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expansion cone 205 having a fluid passage 205a that supports a tubular member 210 that includes a lower portion 210a, an intermediate portion 210b, an upper portion 210c, and an upper end portion 210d.

The expansion cone 205 may be any number of conventional commercially available expansion cones. In several alternative embodiments, the expansion cone 205 may be controllably expandable in the radial direction, for example, as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523.

The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. In several alternative embodiments, the tubular member 210 may be solid and/or slotted. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 12.2 to 6,096 m (40 to 20,000 feet) in length.

The lower portion 210a of the tubular member 210 preferably has a larger inside diameter than the upper portion 210c of the tubular member. In a preferred embodiment, the wall thickness of the intermediate portion 210b of the tubular member 201 is less than the wall thickness of the upper portion 210c of the tubular member in order to facilitate the initiation of the radial expansion process. In a preferred embodiment, the upper end portion 210d of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the expansion cone 205 when it completes the extrusion of tubular member 210. In a preferred embodiment, wall thickness of the upper end portion 210d of the tubular member 210 is gradually tapered in order to gradually reduce the required radial expansion forces during the latter

stages of the radial expansion process. In this manner, shock loading conditions during the latter stages of the radial expansion process are at least minimized.

A shoe 215 is coupled to the lower portion 210a of the tubular member. The shoe 215 includes an upper portion 215a, an intermediate portion 215b, and lower portion 215c having a valveable fluid passage 220 that is preferably adapted to receive a plug, dart, or other similar element for controllably sealing the fluid passage 220. In this manner, the fluid passage 220 may be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 220.

The upper and lower portions, 215a and 215c, of the shoe 215 are preferably substantially tubular, and the intermediate portion 215b of the shoe is preferably at least partially folded inwardly. Furthermore, in a preferred embodiment, when the intermediate portion 215b of the shoe 215 is unfolded by the application of fluid pressure to the interior region 230 of the shoe, the inside and outside diameters of the intermediate portion are preferably both greater than the inside and outside diameters of the upper and lower portions, 215a and 215c. In this manner, the outer circumference of the intermediate portion 215b of the shoe 215 is preferably greater than the outside circumferences of the upper and lower portions, 215a and 215b, of the shoe.

In a preferred embodiment, the shoe 215 further includes one or more through and side outlet ports in fluidic communication with the fluid passage 220. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210.

In an alternative embodiment, the flow passage 220 is omitted.

A support member 225 having fluid passages 225a and 225b is coupled to the expansion cone 205 for supporting the apparatus 200. The fluid passage 225a is preferably fluidicly coupled to the fluid passage 205a. In this manner, fluidic materials may be conveyed to and from the region 230 below the expansion cone 205 and above the bottom of the shoe 215. The fluid passage 225b is preferably fluidicly coupled to the fluid passage 225a and includes a conventional control valve. In this manner, during placement of the apparatus 200 within the wellbore 100, surge pressures can be relieved by the fluid passage 225b. In a preferred embodiment, the support member 225 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200.

During placement of the apparatus 200 within the wellbore 100, the fluid passage 225a is preferably selected to transport materials such as, for example, drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 11356.24 litres/minute and 0 to 620.528 bar (0 to 3,000 gallons/minute and 0 to 9,000 psi) in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore 130 which could cause a loss of wellbore fluids and lead to hole collapse. During placement of the apparatus 200 within the wellbore 100, the fluid passage 225b is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 11356.24 litres/minute and 0 to 620.528 bar (0 to 3,000 gallons/minute and 0 to 9,000 psi) in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

A cup seal 235 is coupled to and supported by the support member 225. The cup seal 235 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expansion cone 205. The cup seal 235 may be any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the cup seal 235 is a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant. In several alternative embodiments, the cup seal 235 may include a plurality of cup seals.

One or more sealing members 240 are preferably coupled to and supported by the exterior surface of the upper end portion 210d of the tubular member 210. The sealing members 240 preferably provide an overlapping joint between the lower end portion 115a of the casing 115 and the upper end portion 210d of the tubular member 210. The sealing members 240 may be any number of conventional commercially available seals such as, for example, lead, rubber, Teflon(RTM), or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 240 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the existing casing 115.

In a preferred embodiment, the sealing members 240 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from

the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the sealing members 240 ranges from about 0.478803 to 478.803 bar (1,000 to 1,000,000 lbf) in order to optimally support the expanded tubular member 210.

In an alternative embodiment, the sealing members 240 are omitted from the upper end portion 210d of the tubular member 210, and a load bearing metal-to-metal interference fit is provided between upper end portion of the tubular member and the lower end portion 115a of the existing casing 115 by plastically deforming and radially expanding the tubular member into contact with the existing casing.

In a preferred embodiment, a quantity of lubricant 245 is provided in the annular region above the expansion cone 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expansion cone 205 is facilitated. The lubricant 245 may be any number of conventional commercially available lubricants such as, for example, Lubriplate(RTM), chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 245 is Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

In a preferred embodiment, the support member 225 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in FIGS. 2 and 2e, in a preferred embodiment, during placement of the apparatus 200 within the wellbore 100, fluidic materials 250 within the wellbore that are displaced by the apparatus are at least partially conveyed through the fluid passages 220, 205a, 225a, and 225b. In this manner, surge pressures created by the placement of the apparatus within the wellbore 100 are reduced.

As illustrated in FIGS. 3, 3a, and 3b, the fluid passage 225b is then closed and a hardenable fluidic sealing material 255 is then pumped from a surface location into the fluid passages 225a and 205a. The material 255 then passes from the fluid passage 205a into the interior region 230 of the shoe 215 below the expansion cone 205. The material 255 then passes from the interior region 230 into the fluid passage 220. The material 255 then exits the apparatus 200 and fills an annular region 260 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 255 causes the material to fill up at least a portion of the annular region 260.

The material 255 is preferably pumped into the annular region 260 at pressures and flow rates ranging, for example, from about 0 to 344.738 bar and 0 to 5618.12 litres/min (0 to 5000 psi and 0 to 1,500 gallons/min), respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 255 may be any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement, latex or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 255 is a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 260. The optimum blend of the blended cement is preferably determined using conventional empirical methods. In several alternative embodiments, the hardenable fluidic sealing material 255 is compressible before, during, or after curing.

The annular region 260 preferably is filled with the material 255 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 260 of the new section 130 of the wellbore 100 will be filled with the material 255.

In an alternative embodiment, the injection of the material 255 into the annular region 260 is omitted, or is provided after the radial expansion of the tubular member 210.

As illustrated in FIGS. 4, 4a, and 4b, once the annular region 260 has been adequately filled with the material 255, a plug 265, or other similar device, is introduced into the fluid passage 220, thereby fluidicly isolating the interior region 230 from the annular region 260. In a preferred embodiment, a non-hardenable fluidic material 270 is then pumped into the interior region 230 causing the interior region to pressurize. In this manner, the interior region 230 of the expanded tubular member 210 will not contain significant amounts of the cured material 255. This also reduces and simplifies the cost of the entire process. Alternatively, the material 255 may be used during this phase of the process.

As illustrated in FIG. 5, in a preferred embodiment, the continued injection of the fluidic material 270 pressurizes the region 230 and unfolds the intermediate portion 215b of the shoe 215. In a preferred embodiment, the outside diameter of the unfolded intermediate portion 215b of the shoe 215 is greater than the outside diameter of the upper and lower portions, 215a and 215b, of the shoe. In a preferred embodiment, the inside and outside diameters of the unfolded intermediate portion 215b of the shoe 215 are greater than the inside and outside diameters, respectively, of the upper and lower portions, 215a and 215b, of the shoe. In a preferred embodiment, the inside diameter of the unfolded intermediate portion 215b of the shoe 215 is substantially equal to or greater than the inside diameter of the preexisting casing 115 in order to optimally facilitate the formation of a mono-diameter wellbore casing.

As illustrated in FIG. 6, in a preferred embodiment, the expansion cone 205 is then lowered into the unfolded intermediate portion 215b of the shoe 215. In a preferred embodiment, the expansion cone 205 is lowered into the unfolded intermediate portion 215b of the shoe 215 until the bottom of the expansion cone is proximate the lower portion 215c of the shoe 215. In a preferred embodiment, during the lowering of the expansion cone 205 into the unfolded intermediate portion 215b of the shoe 215, the material 255 within the annular region 260 and/or the bottom of the wellbore section 130 maintains the shoe 215 in a substantially stationary position.

As illustrated in FIG. 7, in a preferred embodiment, the outside diameter of the expansion cone 205 is then increased. In a preferred embodiment, the outside diameter of the expansion cone 205 is increased as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523. In a preferred embodiment, the outside diameter of the radially expanded expansion cone 205 is substantially equal to the inside diameter of the preexisting wellbore casing 115.

In an alternative embodiment, the expansion cone 205 is not lowered into the radially expanded portion of the shoe 215 prior to being radially expanded. In this manner, the upper portion 210c of the shoe 210 may be radially expanded by the radial expansion of the expansion cone 205.

In another alternative embodiment, the expansion cone 205 is not radially expanded.

As illustrated in FIG. 8, in a preferred embodiment, a fluidic material 275 is then injected into the region 230 through the fluid passages 225a and 205a. In a preferred embodiment, once the interior region 230 becomes sufficiently pressurized, the upper portion 215a of the shoe 215 and the tubular member 210 are preferably plastically deformed, radially expanded, and extruded off of the expansion cone 205. Furthermore, in a preferred embodiment, during the end of the radial expansion process, the upper portion 210d of the tubular member and the lower portion of the preexisting casing 115 that overlap with one another are simultaneously plastically deformed and radially expanded. In this manner, a mono-diameter wellbore casing may be formed that includes the preexisting wellbore casing 115 and the radially expanded tubular member 210.

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In this manner, an overlapping joint between the radially expanded tubular member 210 and the lower portion of the preexisting casing 115 may be optimally formed. In an alternative preferred embodiment, the expansion cone 205 is maintained in a stationary position during the extrusion process thereby allowing the tubular member 210 to extrude off of the expansion cone 205 and into the new wellbore section 130 under the force of gravity and the operating pressure of the interior region 230.

In a preferred embodiment, when the upper end portion 210d of the tubular member 210 and the lower portion of the preexisting casing 115 that overlap with one another are plastically deformed and radially expanded by the expansion cone 205, the expansion cone 205 is displaced out of the wellbore 100 by both the operating pressure within the region 230 and a upwardly directed axial force applied to the tubular support member 225.

The overlapping joint between the lower portion of the preexisting casing 115 and the radially expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint. In an alternative embodiment, the sealing members 245 are omitted.

In a preferred embodiment, the operating pressure and flow rate of the fluidic material 275 is controllably ramped down when the expansion cone 205 reaches the upper end portion 210d of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expansion cone 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the expansion cone 205 is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, the wall thickness of the upper end portion 210d of the tubular member is tapered in order to gradually reduce the required operating pressure for plastically deforming and radially expanding the upper end portion of the tubular member. In this manner, shock loading of the apparatus is at least reduced.

Alternatively, or in combination, a shock absorber is provided in the support member 225 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber, bumper sub, or jars adapted for use in wellbore operations.

Alternatively, or in combination, an expansion cone catching structure is provided in the upper end portion 210d of the tubular member 210 in order to catch or at least decelerate the expansion cone 205.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion cone 205, the material composition of the tubular member 210 and expansion cone 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the expansion cone 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expansion cone 205 will begin when the pressure of the interior region 230 reaches, for example, approximately 34.47 to 620.53 bar (500 to 9,000 psi).

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 1.524 metres/sec (0 to 5 ft/sec). In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 0.6096 metres/sec (0 to 2 ft/sec) in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

As illustrated in FIG. 9, once the extrusion process is completed, the expansion cone 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expansion cone 205, the integrity of the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the preexisting wellbore casing 115 is tested using conventional methods.

In a preferred embodiment, if the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the casing 115 is satisfactory, then any uncured portion of the material 255 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The expansion cone 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly to drill out any hardened material 255 within the tubular member 210. In a preferred embodiment, the material 255 within the annular region 260 is then allowed to fully cure.

As illustrated in FIG. 10, the bottom portion 215c of the shoe 215 may then be removed by drilling out the bottom portion of the shoe using conventional drilling methods. The wellbore 100 may then be extended in a conventional manner using a conventional drilling assembly. In a preferred embodiment, the inside diameter of the extended portion of the wellbore 100 is greater than the inside diameter of the radially expanded shoe 215.

As illustrated in FIG. 11, the method of FIGS. 1-10 may be repeatedly performed in order to provide a mono-diameter wellbore casing that includes

overlapping wellbore casings 115 and 210a-210e. The wellbore casing 115, and 210a-210e preferably include outer annular layers of fluidic sealing material. Alternatively, the outer annular layers of fluidic sealing material may be omitted. In this manner, a mono-diameter wellbore casing may be formed within the subterranean formation that extends for thousands of metres (tens of thousands of feet). More generally still, the teachings of FIGS. 1-11 may be used to form a mono-diameter wellbore casing, a pipeline, a structural support, or a tunnel within a subterranean formation at any orientation from the vertical to the horizontal.

Referring to FIGS. 12, 12a, 12b, 12c, and 12d, in an alternative embodiment, an apparatus 300 for forming a mono-diameter wellbore casing is positioned within the wellbore casing 115 that is substantially identical in design and operation to the apparatus 200 except that a shoe 305 is substituted for the shoe 215.

In a preferred embodiment, the shoe 305 includes an upper portion 305a, an intermediate portion 305b, and a lower portion 305c having a valveable fluid passage 310 that is preferably adapted to receive a plug, dart, or other similar element for controllably sealing the fluid passage 310. In this manner, the fluid passage 310 may be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 310.

The upper and lower portions, 305a and 305c, of the shoe 305 are preferably substantially tubular, and the intermediate portion 305b of the shoe includes corrugations 305ba-305bh. Furthermore, in a preferred embodiment, when the intermediate portion 305b of the shoe 305 is radially expanded by the application of fluid pressure to the interior 315 of the shoe 305, the inside and outside diameters of the radially expanded intermediate portion are preferably both greater than the inside and outside diameters of the upper and lower portions, 305a and 305c. In this manner, the outer circumference of the intermediate portion 305b of the shoe 305 is preferably greater than the outer circumferences of the upper and lower portions, 305a and 305c, of the shoe.

In a preferred embodiment, the shoe 305 further includes one or more through and side outlet ports in fluidic communication with the fluid passage 310. In this manner, the shoe 305 optimally injects hardenable fluidic sealing material into the region outside the shoe 305 and tubular member 210.

In an alternative embodiment, the flow passage 310 is omitted.

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In a preferred embodiment, as illustrated in FIGS. 12 and 12d, during placement of the apparatus 300 within the wellbore 100, fluidic materials 250 within the wellbore that are displaced by the apparatus are conveyed through the fluid passages 310, 205a, 225a, and 225b. In this manner, surge pressures created by the placement of the apparatus within the wellbore 100 are reduced.

In a preferred embodiment, as illustrated in FIG. 13 and 13a, the fluid passage 225b is then closed and a hardenable fluidic sealing material 255 is then pumped from a surface location into the fluid passages 225a and 205a. The material 255 then passes from the fluid passage 205a into the interior region 315 of the shoe 305 below the expansion cone 205. The material 255 then passes from the interior region 315 into the fluid passage 310. The material 255 then exits the apparatus 300 and fills the annular region 260 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 255 causes the material to fill up at least a portion of the annular region 260.

The material 255 is preferably pumped into the annular region 260 at pressures and flow rates ranging, for example, from about 0 to 344.738 bar and 0 to 5618.12 litres/min (0 to 5000 psi and 0 to 1,500 gallons/min), respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 255 may be any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement, latex or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 255 is a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 260. The optimum blend of the blended cement is preferably determined using conventional empirical methods. In several alternative embodiments, the hardenable fluidic sealing material 255 is compressible before, during, or after curing.

The annular region 260 preferably is filled with the material 255 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular

region 260 of the new section 130 of the wellbore 100 will be filled with the material 255.

In an alternative embodiment, the injection of the material 255 into the annular region 260 is omitted.

As illustrated in FIGS. 14 and 14a, once the annular region 260 has been adequately filled with the material 255, a plug 265, or other similar device, is introduced into the fluid passage 310, thereby fluidicly isolating the interior region 315 from the annular region 260. In a preferred embodiment, a non-hardenable fluidic material 270 is then pumped into the interior region 315 causing the interior region to pressurize. In this manner, the interior region 315 will not contain significant amounts of the cured material 255. This also reduces and simplifies the cost of the entire process. Alternatively, the material 255 may be used during this phase of the process.

As illustrated in FIG. 15, in a preferred embodiment, the continued injection of the fluidic material 270 pressurizes the region 315 and unfolds the corrugations 305ba-305bh of the intermediate portion 305b of the shoe 305. In a preferred embodiment, the outside diameter of the unfolded intermediate portion 305b of the shoe 305 is greater than the outside diameter of the upper and lower portions, 305a and 305b, of the shoe. In a preferred embodiment, the inside and outside diameters of the unfolded intermediate portion 305b of the shoe 305 are greater than the inside and outside diameters, respectively, of the upper and lower portions, 305a and 305b, of the shoe. In a preferred embodiment, the inside diameter of the unfolded intermediate portion 305b of the shoe 305 is substantially equal to or greater than the inside diameter of the preexisting casing 305 in order to optimize the formation of a mono-diameter wellbore casing.

As illustrated in FIG. 16, in a preferred embodiment, the expansion cone 205 is then lowered into the unfolded intermediate portion 305b of the shoe 305. In a preferred embodiment, the expansion cone 205 is lowered into the unfolded intermediate portion 305b of the shoe 305 until the bottom of the expansion cone is proximate the lower portion 305c of the shoe 305. In a preferred embodiment, during the lowering of the expansion cone 205 into the unfolded intermediate portion 305b of the shoe 305, the material 255 within the annular region 260 maintains the shoe 305 in a substantially stationary position.

As illustrated in FIG. 17, in a preferred embodiment, the outside diameter of the expansion cone 205 is then increased. In a preferred embodiment, the outside

diameter of the expansion cone 205 is increased as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523. In a preferred embodiment, the outside diameter of the radially expanded expansion cone 205 is substantially equal to the inside diameter of the preexisting wellbore casing 115.

In an alternative embodiment, the expansion cone 205 is not lowered into the radially expanded portion of the shoe 305 prior to being radially expanded. In this manner, the upper portion 305c of the shoe 305 may be radially expanded by the radial expansion of the expansion cone 205.

In another alternative embodiment, the expansion cone 205 is not radially expanded.

As illustrated in FIG. 18, in a preferred embodiment, a fluidic material 275 is then injected into the region 315 through the fluid passages 225a and 205a. In a preferred embodiment, once the interior region 315 becomes sufficiently pressurized, the upper portion 305a of the shoe 305 and the tubular member 210 are preferably plastically deformed, radially expanded, and extruded off of the expansion cone 205. Furthermore, in a preferred embodiment, during the end of the radial expansion process, the upper portion 210d of the tubular member and the lower portion of the preexisting casing 115 that overlap with one another are simultaneously plastically deformed and radially expanded. In this manner, a mono-diameter wellbore casing may be formed that includes the preexisting wellbore casing 115 and the radially expanded tubular member 210.

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In this manner, an overlapping joint between the radially expanded tubular member 210 and the lower portion of the preexisting casing 115 may be optimally formed. In an alternative preferred embodiment, the expansion cone 205 is maintained in a stationary position during the extrusion process thereby allowing the tubular member 210 to extrude off of the expansion cone 205 and into the new wellbore section 130 under the force of gravity and the operating pressure of the interior region 230.

In a preferred embodiment, when the upper end portion 210d of the tubular member 210 and the lower portion of the preexisting casing 115 that overlap with one

another are plastically deformed and radially expanded by the expansion cone 205, the expansion cone 205 is displaced out of the wellbore 100 by both the operating pressure within the region 230 and a upwardly directed axial force applied to the tubular support member 225.

The overlapping joint between the lower portion of the preexisting casing 115 and the radially expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint. In an alternative embodiment, the sealing members 245 are omitted.

In a preferred embodiment, the operating pressure and flow rate of the fluidic material 275 is controllably ramped down when the expansion cone 205 reaches the upper end portion 210d of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expansion cone 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the expansion cone 205 is within about 1.524 metres (5 feet) from completion of the extrusion process.

Alternatively, or in combination, the wall thickness of the upper end portion 210d of the tubular member is tapered in order to gradually reduce the required operating pressure for plastically deforming and radially expanding the upper end portion of the tubular member. In this manner, shock loading of the apparatus may be at least partially minimized.

Alternatively, or in combination, a shock absorber is provided in the support member 225 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, an expansion cone catching structure is provided in the upper end portion 210d of the tubular member 210 in order to catch or at least decelerate the expansion cone 205.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion cone 205, the material composition of the tubular member 210 and expansion cone 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the

type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the expansion cone 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expansion cone 205 will begin when the pressure of the interior region 230 reaches, for example, approximately 34.47 to 620.53 bar (500 to 9,000 psi).

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 1.524 metres/sec (0 to 5 ft/sec). In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 0.6096 metres/sec (0 to 2 ft/sec) in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

As illustrated in FIG. 19, once the extrusion process is completed, the expansion cone 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expansion cone 205, the integrity of the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the preexisting wellbore casing 115 is tested using conventional methods.

In a preferred embodiment, if the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the casing 115 is satisfactory, then any uncured portion of the material 255 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The expansion cone 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly to drill out any hardened material 255 within the tubular member 210. In a preferred embodiment, the material 255 within the annular region 260 is then allowed to fully cure.

As illustrated in FIG. 20, the bottom portion 305c of the shoe 305 may then be removed by drilling out the bottom portion of the shoe using conventional drilling methods. The wellbore 100 may then be extended in a conventional manner using a conventional drilling assembly. In a preferred embodiment, the inside diameter of the

extended portion of the wellbore is greater than the inside diameter of the radially expanded shoe 305.

The method of FIGS. 12-20 may be repeatedly performed in order to provide a mono-diameter wellbore casing that includes overlapping wellbore casings. The overlapping wellbore casing preferably include outer annular layers of fluidic sealing material. Alternatively, the outer annular layers of fluidic sealing material may be omitted. In this manner, a mono-diameter wellbore casing may be formed within the subterranean formation that extends for thousands of metres (tens of thousands of feet). More generally still, the teachings of FIGS. 12-20 may be used to form a mono-diameter wellbore casing, a pipeline, a structural support, or a tunnel within a subterranean formation at any orientation from the vertical to the horizontal.

In several alternative embodiments, the apparatus 200 and 300 are used to form and/or repair wellbore casings, pipelines, and/or structural supports.

In several alternative embodiments, the folded geometries of the shoes 215 and 305 are provided in accordance with the teachings of U.S. Patent Nos. 5,425,559 and/or 5,794,702.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure within the scope of the claims.

## CLAIMS

1. An apparatus for forming a wellbore casing within a subterranean formation including a preexisting wellbore casing positioned in a borehole, comprising:

a tubular liner; and

means for radially expanding and coupling the tubular liner to an overlapping portion of the preexisting wellbore casing;

wherein the inside diameter of the radially expanded tubular liner is equal to the inside diameter of a non-overlapping portion of the preexisting wellbore casing, and

wherein the means for radially expanding and coupling the tubular liner comprises an expandable shoe coupled to the tubular liner.

2. An apparatus for forming a tubular structure within a subterranean formation including a preexisting tubular member positioned in a borehole, comprising:

a tubular liner; and

means for radially expanding and coupling the tubular liner to an overlapping portion of the preexisting tubular member;

wherein the inside diameter of the radially expanded tubular liner is equal to the inside diameter of a non-overlapping portion of the preexisting tubular member, and

wherein the means for radially expanding and coupling the tubular liner comprises an expandable shoe coupled to the tubular liner.